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EFFECT OF ACCURACY OF
WIND POWER PREDICTION ON
POWER SYSTEM OPERATOR

Robert A. Schlueter, Principal Investigator
G. Sigari
T. Costi

FINAL REPORT

June, 1985

Report Prepared by the

Division of Engineering Research

Michigan State University

East Lansing, Michigan 48824

for the

COLLEGE OF ENGINEERING

MICHIGAN STATE UNIVERSITY

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FORWARD

This report was prepared by the Division of Engineering Research at Michigan State University under Contract NAG3-399 from the Wind Projects Office at NASA Lewis Research Center. Project managers for this contract were Mr. William Schmidt, and Art Birchenough.

ABSTRACT

This research project proposed a modified unit commitment that schedules connection and disconnection of generating units in response to load. A modified generation control is also proposed that controls steam units under automatic generation control, fast responding diesels, gas turbines and hydro units under a feedforward control, and wind turbine array output under a closed loop array control. This modified generation control and unit commitment require prediction of trend wind power variation one hour ahead and the prediction of error in this trend wind power prediction one half hour ahead. An improved method for predicting trend wind speed variation is developed. Methods for accurately simulating the wind array power from a limited number of wind speed prediction records was developed. Finally, two methods for predicting the error in the trend wind power prediction were developed. This research provides a foundation for testing and evaluating the modified unit commitment and generation control that was developed to maintain operating reliability at a greatly reduced overall production cost for utilities with wind generation capacity.

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The purpose of the research is the development of:

(1) a modified unit commitment;

(2) a modified generation control;

(3) a trend wind power predictor required by both the modified unit commitment and generation control procedures developed;

(4) a wind power error predictor required by both the modified unit commitment and generation control procedures.

These four developments permit one to answer the following two questions which are to be addressed by the research to be conducted within the Federal Winds Energy Research Plan: 1985-1990

(1) what is the magnitude of the capacity credit that can be assigned to wind energy produced by large arrays based on methods for setting and meeting the load following and operating reserve requirements within a utility's unit commitment. This magnitude of the capacity credit assigned to wind will determine the breakeven point in terms of 30 year levelized cost in $/KWH that wind energy technology must achieve to warrant large scale implementation by utilities.

(2) Develop a generation control strategy that minimizes the impact of large rapid changes in wind array generation that is caused by "rotor synchronization" [1, A-3. III-20] of all wind turbines in the array for large meteorological event wind speed changes. The utility's steam turbine generation is slow responding and cannot compensate for these large rapid wind generation changes. Attempting to force these units to compensate for these large wind generation changes would cause cycling in these units that would expend significant fuel, increase maintenance, and possibly reduce unit reliability and lifetime. A modified generation control is proposed in this research based on an hour ahead prediction of wind power change. This modified generation control would utilize these slow responding large steam turbine units up to a limit imposed by the utility; fast responding diesels, hydros and gas turbines that are not presently effectively controlled, and wind turbine array control of wind power output as a last resort.

This modified generation control strategy has been developed to allow the utility to determine the level of participation its large steam turbine units should have in compensating for large wind generation changes. This modified generation control was designed so that quick pickup units provide the principal compensation for the large wind change. The modified quarter hour updated unit commitment strategy would continually unload these quick pickup units and replace them with standby economic, peaking, and regulating units. The purpose of maintaining quick pickup generation is spinning

reserve is to maintain adequate spinning reserve and load following margins to compensate for large drops in wind generation. If the wind generation increase exceeds the allocated combination of the response capability of large steam turbines under automatic generation control and the level of quick pickup generation connected and loaded (that could be unloaded and disconnected in 15 minutes by the feedforward generation control to compensate for the wind generation increase), the closed loop wind turbines array control would reduce the wind generation rate of change to the level the AGC and feedforward control could handle. For wind generation decreases, the AGC would again compensate for the wind generation change up to the capability allocated to tracking wind generation change. The feedforward control of quick pickup units would then be capable of connecting and fully loading all quick pickup generation within the spinning reserve within fifteen minutes to compensate for wind generation decrease. The quarter hour unit commitment would schedule their connection and the feedforward generation control would set the gain on their governor controls so that they would be properly loaded. These quick pickup units, once connected, would be controlled utilizing the area control error signal used for regulating units under AGC. The participation factor on the quick pickup units would be adjusted by the feedforward generation control to obtain the desired generation change out of these quick pickup units and thereby prevent units under AGC from exceeding the allocated response capability assigned to compensating for wind generation. If the predicted wind generation decrease is greater than the combined response capability of the feedforward generation control and the allocated response capability of the units under AGC, then the closed loop array control attempts to build up a back off reserve on the wind turbines by clipping wind generation below the level that would otherwise be produced given the present wind speed at the particular time. This back off reserve is utilized as a cushion so that when the predicted drop in wind generation occurs it is not larger than could be handled by AGC and feedforward control within 15 minutes. The development of the back off reserve is possible due to the hour ahead prediction interval and the fact that the level of wind generation to be clipped is based on the maximum predicted wind generation decrease (trend wind power minus the error in the trend wind power prediction) and not just the trend wind power change.

Although the structure of the modified generation control has been developed, it has not been evaluated or tested via simulation. The simulation of this generation control utilizing predicted trend wind power changes and predicted wind power errors of the typical utilities that could expect to have large wind penetrations would be a subject for future research.

A trend wind power predictor was developed in this research project. The research in this project showed:

(1) time filtering wind speeds caused significant distortion of the maximum, minimum, and average values in wind speeds prediction and could introduce significant delays;

(2) time filtering is not required to determine meteorological event propagation direction, the reference groups used to predict wind

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speed at prediction sites in the wind array or propagation delays between referenced and prediction sites. This is a change from the wind speed prediction method developed in [20];

(3) the reference measurement sites should encircle the wind turbine cluster at a distance of at least 100 miles away from all wind turbine clusters. Meteorological events can propagate at speeds between 0-100 mph and thus a 100 mile separation allows one or more hour ahead trend wind power prediction;

(4) the reference groups should not contain storm cell induced cyclic variation because such variation is site specific and time varying. Using reference sites with cyclic storm induced variation prevents prediction of the trend changes in wind speed that are associated with the storm front and can be predicted;

(5) the reference groups used for prediction should change when the wind shift associated with an incoming front first affects a particular cluster of wind turbines. The reference group should change from one that is in front of the wind array in the direction of propagation of the initial meteorological event to reference sites that are in front of the wind turbine array in the propagation direction of the incoming event;

(6) the use of several wind speed reference sites introduces a spatial filtering of wind speed variation associated with a meteorological event. This spatial filtering associated with the wind speed prediction is shown to cause the predicted wind power variation to exceed the actual wind power produced by the array by as much as 10-20%;

(7) several wind prediction sites are required to produce accurate wind array power estimates. The error utilizing a single wind speed prediction site to simulate a 90 wind turbine array could be as large as 100% depending on the prediction site selected within that wind turbine array. The error could be reduced to 25% if three reference sites are used. The larger the number of prediction sites the smaller will be the effect of site specific effects and wind speed prediction errors of any prediction site. If the wind speed at each wind turbine is not predicted due to the computational burden, then one should select prediction sites so that each prediction site is geographically closest to an equal number of wind turbine sites. This method of siting wind prediction sites minimizes the site specific effects and error of any one wind prediction site on the total array power prediction;

(8) the study of five different methods of simulating wind array power variations indicates that there can be significant differences between the results obtained using different methods. These differences are minimized as the number of wind prediction sites increases. No one method of simulating wind array power variation will be most accurate for all wind conditions since the magnitude of the error and site specific variation at a wind prediction site will

vary with the wind conditions. Since each simulation method mini-mizes effects of error at specific sites and accentuate error at other sites, no one simulation method can give the most accurate estimate of true wind array power variation for all wind conditions;

(9) the magnitude of the wind array power prediction error depends on the magnitude of the storm induced cyclic variation and turbulence induced wind power variation that can not be predicted using the trend wind power predictor. The error in the trend wind power predictor due to the spatial filtering in the wind speed predictor also contributes to wind array power prediction error. This wind power prediction error can be the magnitude of the capacity of the wind array during storms since the large cyclic variations can cause cycling between zero and rated array capacity. The error is so large because the cyclic variation which can not be predicted using this methodology. The wind power prediction error can be kept below 10% - 25% for other wind conditions if a sufficient number of wind power prediction sites are used to simulate the wind array power variation.

A wind power prediction error predictor was also developed. The wind speed prediction error was shown to be a zero mean and normal at sites where wind speed prediction is successfully accomplished. The wind power prediction error was shown to be slowly time varying. Thus, a wind power error predictor was proposed that averages the absolute error between the actual array power output and the predicted array power over a 15 or 30 minute period and uses this error estimate to predict power 30 minutes ahead. This predicted error is not allowed to be less than 10% of the wind array power output since even though the error may become very small for a period of time it does reflect the error that can be expected to occur at some time in the future. This wind power prediction error predictor was thoroughly tested. The error band around the predicted array power was shown to effectively band the actual wind power variation.

The following accomplishments of this research project are unique:

(1) the development of wind speed prediction for meteorological events and turbulence induced variation. Prediction of wind speed based on turbulence alone was performed in [2], but the magnitude of turbulence induced variation is so small compared to meteorological event variation that it does not require prediction to assure power system reliability and economy;

(2) the development of a method for predicting the error in the wind power predictor;

(3) the development of wind power prediction methods. The assessment of different wind power prediction methods, the effect of increasing the number of wind power prediction sites in the array, the proper siting of these prediction sites and the proper simulation method for producing array power variation from several wind speed prediciton sites were all investigated in the research;

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(4) investigation of a modified unit commitment procedure that would greatly increase the capacity credit given to wind generation. Without trend wind power prediction and wind power error prediction, a utility would not be able to connect or disconnect nonwind generation in proportion to predicted wind generation increase or decrease respectively. Thus, although one could achieve a capacity credit based on LOLF calculations, the operation of the utility effectively prevented wind generation from serving any load since no nonwind generation capacity is displaced by wind generation. The modified unit commitment procedure proposed would increase load following and spinning reserve proportional to the magnitude of the wind power prediction error. The magnitude of the spinning reserve increase at any time, which is proportional to wind power prediction error at that time, is the amount of the wind generation that is not allowed to be counted at meeting load due to the lack of perfect prediction of wind power variation. Wind power prediction thus permits one to provide capacity credit for wind and improvements in wind power prediction accuracy increase the capacity credit given to wind array power variation. The research performed in this project is the only published research on modified unit commitment methods that can utilize wind power prediction to modify the 24 hour unit commitment based on predicted wind generation changes;

(5) the development of a generation control strategy based on the one developed in [8] but that utilizes both the trend wind power predictor and the wind power prediction error predictor for both meteorological event and turbulence induced variation. The generation control utilizes the control philosophy in the priority use of automatic generation control feedforward control, and array control but incorporates the effects of predicting meteorological events and the effects of wind array power prediction error. The generation control strategy proposed would satisfy utility reliability requirements while simultaneously assuring economic operation. Furthermore, the proposed generation control would limit the cycling on large steam units that would increase fuel costs, increase forced outages, and possibly reduce unit lifetime.

However, the methodology has not been integrated into an individual package. Thus, the capabilities and performances of the modified unit commitment and modified generation control can not be fully quantified and validated and should be evaluated in a future research project.

SECTION 1

INTRODUCTION

Two fundamental questions that are to be addressed in the Federal Wind Energy Five Year Research Plan. 1985-1990 [1] have been investigated and partially answered in this research project. These two questions are:

1. What is the magnitude of capacity credit that can be assigned to wind energy produced from large arrays based on development of methods for setting load following and operating reserve levels [1, pg. A4]. The

    methods for setting and meeting operating and load following requirements must meet the utility operating reliability standards [19] but have tremendous impact on the economic breakeven price of wind energy where utilities would likely begin large scale implementation of wind development. If there are no capacity credits given to wind because of operating reserve and load following requirements, the long term economic breakeven point in 30 year levelized cost for wind energy would be 3 /kWh [1, A3]. If the load following and operating reserve requirement give capacity credit to wind energy, then wind need not be justified solely based on fuel displacement and the economic breakeven price of wind energy would decrease substantially. This research project develops a modified unit commitment procedure based on an hour ahead wind power prediction that can provide significant capacity credits that depend on the accuracy of the wind array power prediction at any time;

(2) Develop a generation control strategy that minimizes the impact of large rapid changes in wind array generation that is caused by "rotor synchronization" [1, A-3, III-20] of all wind turbines in the array for large meteorological event wind speed changes. The utility's steam turbine generation is slow responding and cannot compensate for these large rapid wind generation changes. Attempting to force these units to compensate for these large wind generation changes would cause cycling in these units that would expend significant fuel, increase maintenance, and possibly reduce unit reliability and lifetime. A modified generation control is proposed in this research based on an hour ahead prediction of wind power change. This modified generation control would utilize these slow responding large steam turbine units up to a limit composed by the utility; fast responding diesels, hydros and gas turbines that are not presently effectively controlled, and wind turbine array control of wind power output as a last resort.

There are four major contributions of this research:

1. Development of a new modified unit commitment procedure that utilizes an hour ahead prediction of trend wind power change and an hour ahead prediction of the error in this trend wind power prediction. This new unit procedure would provide significant capacity credit for wind energy (8% - 30%) based on both the magnitude of the wind power predicted over the next hour and the estimate of the error in this prediction;

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2. Development of a new generation control that minimizes the impact of
    large rapid "rotor synchronized" array wind power changes on large slow
    responding steam turbine units; utilizes the fast responding diesels, gas
    turbines, and hydro units to provide the primary compensation for these
    large rapid wind energy changes; and utilizes wind array controls to
    reduce wind energy changes only when required to maintain the utility's
    operating reliability;

3. Development of a wind power prediction methodology based (a) on
    improvements in the previously developed wind speed prediction
    methodology [20] and (b) development and assessment of alternate methods
    for simulating predicted wind array power from the predicted wind speeds
    at one or more sites in the wind turbine array;

4. Development of a wind power prediction error predictor that can estimate
    the magnitude of the error in the prediction of trend wind power
    variation. This wind power prediction error predictor would estimate the
    (a) magnitude of the large cyclic variations in wind array power due to
    passage of storm cells through an array; (b) the magnitude of turbulence
    induced wind power variations in the array; and (c) the magnitude of the
    error in the prediction of trend wind power change. The need to estimate
    the trend wind prediction error is due to the fact that (1) this error is
    very large compared to the error in predicting electric power demand
    (load) over a 24 hour or hour period and (2) this error has major
    impact on the capacity credit assigned to wind energy in setting load
    following and operating reserve requirements in the new unit commitment
    procedure. This error in wind power prediction would also determine
    whether feed forward generation control of gas turbines, diesels, and
    hydro units needs to be utilized over the next 15 minute period and the
    magnitude of the reduction in wind generation change that the closed loop
    control of wind array power should allow.

    The remainder of this section reviews the work performed under these four
major contributions and where it is presented in this report.

    The new unit commitment procedure, developed and presented in Section 2
of this report, is a significant extension of a modified unit commitment
procedure developed by Michigan State University in [3]. The unit commitment
procedure developed earlier [3] assumed that both front and storm
meteorological event induced wind power variation could be accurately
predicted. The results in Section 4 of this report indicate that the trend
variation in both front and storms can be predicted one hour ahead but that
the large cyclic variation in storms cannot be predicted using the wind speed
prediction methods utilized in this research. The unit commitment procedure
[3] proposed that a minute updated unit commitment procedure could be
implemented based on an accurate quarter hour ahead prediction of storm
induced cyclic variation. Moreover, no explicit method was proposed in [3]
for estimating the error in the hour ahead wind power prediction as is
developed in Section 2 and 7 of this report. The unit commitment procedure
proposed in Section 2 would allow the present 24 hour ahead unit commitment to
schedule connection and disconnection of large steam turbine peaking, and
quick pickup units based on a 24 hour ahead prediction of load and a 24 hour

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ahead prediction of diurnal wind power variation. Operating, reserve, and load following requirements would be set assuming these 24 hour forecasts of wind power were accurate and that the wind array power variation due to meteorological events was small. A quarter hour updated unit commitment would then be utilized to schedule connection of quick pickup and standby economic, peaking, and regulating units to compensate for large meteorological event induced wind power variation. This quarter hour updated unit commitment would be based on a hour ahead prediction of trend wind power variation as well as an estimate of the error in this trend wind power predictor. The error in this predictor would be an estimate of the magnitude of the (a) large storm induced cyclic power variation, (b) turbulence induced wind power variation, and (c) error in the trend wind power prediction. Methods for setting spinning reserve, unloadable generation reserve, and load following reserve within the quarter hour unit commitment are developed. A method that requires additional research is proposed for setting operating reserve within the quarter hour unit commitment. Methods for meeting these reserve requirements as well as minimizing production cost, satisfying minimum shutdown and startup constraints, and satisfying minimum and maximum generation constraints on generators, within this quarter updated hour unit commitment procedure, are discussed.

A new generation control procedure is developed in Section 2 that is a significant extension of the one developed by General Electric in [8]. This new generation control procedure utilizes the trend wind power prediction as well as the estimate of trend wind power prediction error. This new generation control procedure permits the utility to decide the maximum load following response capability in MW/minute to be devoted to compensating for wind power variations. If predicted maximum wind power change exceeds this capability, then a feedforward control of fast responding quick pickup units (diesels, gas turbines, hydros), are utilized to compensate for these large wind power variations. This generation control is coordinated with the quarter hour unit commitment so that standby economic, peaking and regulating units are connected to replace quick pickup units that are connected and loaded by the feedforward generation control to compensate for wind generation decreases. The quick pickup generation is unloaded and disconnected if large wind generation increases are experienced. These quick pickup units are the primary compensation for large wind generation increases because they can be connected and loaded or unloaded and disconnected in fifteen minutes. The actual control of the level of generation in the feedforward control would depend on area control error in a manner similar to that used on regulating units on AGC. If the maximum predicted wind power change in fifteen minutes exceeds the maximum response rate capability of the combination of quick pickup units under feedforward control and the allocated maximum response of steam turbine units for wind variation, then closed loop control of array power output would limit wind generation change to a level that could be handled by automatic generation control and the feedforward generation control. Wind generation increase can be limited to any desired value by the closed loop wind generation control. The ability to predict trend wind generation change one hour ahead and the use of a maximum possible wind generation decrease to determine the rate of generation decrease for the closed loop array control allows the development of a backoff reserve that would help compensate for large sudden drops in wind speed.

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The generation control is a very significant extension of the work performed in [8] because it utilizes the trend prediction of meteorological event wind power variation rather than a crude Davenport spectrum based prediction of turbulence induced variation. The use of wind power error prediction as well as trend wind power prediction to determine when the feedforward control and the closed loop array control is required and to determine the amount of the wind array power variation to eliminate via closed loop array control are two other significant contributions of the research reported in Section 2. Finally, the ability to limit the response of units under automatic generation control for wind generation change and the ability to coordinate the quarter hour updated unit commitment and feedforward generation control to maintain sufficient quick pickup units in spinning reserve and response (load following) capability are contributions of this work.

The third major contribution of this research is the development of a wind array power prediction methodology and the assessment of its accuracy and limitations. An improved wind speed prediction methodology is described in Section 3 of this report along with a review of previous literature on wind prediction. The wind speed prediction methodology requires determining the direction of propagation of the meteorological event, the speed of propagation of the event and thus the delays between reference measurement sites and the wind speed prediction sites in the wind turbine cluster. Methods for selecting reference groups to insure accurate trend wind speed prediction for meteorological events and for changing reference groups for arrival of a front are discussed. The need to provide reference measurement sites that encircle all wind turbine clusters at a radius of 100 miles is indicated to be required to insure hour ahead wind prediction regardless of the direction of propagation of the event. Finally, individual prediction site, reference group/prediction site, and reference group/prediction group predictive models are described along with the least square procedure for estimating parameters of these models.

The accuracy and limitations of the improved wind speed prediction methodology is assessed in Chapter 4. It is shown that the individual site predictive model is much more accurate than either the prediction site/reference group or prediction group/reference group models. It is shown that filtering the wind speed records seriously distorts the accuracy of the wind speed prediction and is not required for determining reference groups, direction of propagation of the front, or prediction delays. Our earlier work [3] on wind speed prediction utilized filtering and is shown to seriously distort the accuracy of the prediction and is not otherwise required to enhance the information in the record required to determine propagation direction, reference groups, and prediction delays. It is shown that the large cyclic variations due to storm cells passing through the prediction sites cannot be predicted due to their variation over both time and distance. Reference sites that did not contain storm induced variation was shown to much more accurately predict the trend change in wind speed at sites regardless of whether they experienced storm cell induced cyclic variation or not. It was also found that utilizing reference sites that are closer to prediction sites proportionately reduces the prediction interval and reduces prediction error. A 100 mile separation between the reference sites that encircle the prediction sites was seen to be necessary because the speed of propagation of a meteorological event can be as high as 100 mph and as low as 0 mph when wind

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speeds are 0 to 40 mph.

The development of the wind array power prediction is begun in Section 5. The use of several reference sites to produce a predicted wind speed record is shown to be equivalent to a spatial filtering of the wind speed profile of a meteorological event. This spatial filtering is shown to occur by time filtering the reference wind speed record used to produce the predicted wind speed at sites within the wind array and ultimately the simulated power out of a wind turbine array. The actual wind speed measurement records at the prediction sites in the array are also filtered and then used to simulate wind array power. The filtering of the actual wind speed measurement records causes a significant increase of power out of the array when wind speed is near rated wind turbine velocity by increasing the average wind speed and increasing the period of saturation of the wind turbines. The filtering also significantly distorts average minimum and maximum wind power variation. The filtering of wind speed before producing the predicted wind speed records that are ultimately utilized to produce predicted array power had almost no effect. Thus, the spatial filtering caused by utilizing several wind speed measurements for wind speed prediction is inferred. A comparison of the predicted and actual wind array power variation for unfiltered wind speed records indicates that the predicted wind array power is always greater than the actual wind array power due to this spatial filtering. The cyclic variation in the actual wind power record is not evident in the predicted array power record due to the spatial filtering. The error in predicting the wind power variation in fronts is 10-20% but can be as large as 100% during passage of storm cells since the large cyclic variation cannot be predicted.

The use of two wind prediction sites to simulate the wind array power is also investigated in Section 5 to determine if using more than one prediction site to simulate the wind array power will cause any significant difference. The large variation in the mean, rms, and shape of the predicted wind speeds at the two geographically close wind prediction sites caused rather large differences between the array power simulated using a single wind prediction site record and an average of both wind prediction site records.

The development of the wind array power prediction methodology is completed in Section 6 by a study of various methods of simulating wind array power using multiple wind prediction sites. Method 1 utilizes a single wind prediction record. Methods 2 and 3 produce an average wind turbine power record by either averaging wind speed before simulating power from a wind turbine (Method 2) or by averaging the simulated power out of a wind turbine that experiences the predicted wind speed record (Method 3). The wind array power record is produced from this average wind turbine power record by summing a delayed average wind turbine power record for each wind turbine in the array. The delay used is based on the geographical location of that wind turbine from the first turbine to be affected by the propagation of the front and the speed of propagation of the front. Methods 4, 5, and 6 for simulating wind power simulate the power out of subarrays of wind turbines that are closest to a particular wind speed prediction site. Method 4 utilizes a single wind prediction record for a subarray. Methods 5 and 6 utilize the closest two wind measurement records to the wind turbines in the subarray and produce an average wind turbine power record for the subarray. Method 5 averages the two wind speed records and then simulates the average wind tur-

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bine power record for the subarray. Method 6 simulates the power from a wind turbine at each wind prediction site and then averages the two wind power records for the wind speed prediction sites that are closest to the subarray of wind turbines. The power out of a subarray using Methods 4-6 produces the total subarray power record by summing a delayed average subarray turbine power record for each wind turbine in the subarray using a delay based on the distance from the first wind turbine in the subarray to be affected by the propagation of the meteorological event. The total array power record is produced by summing the subarray power records.

The results of simulating wind array power showed that the wind array power based on one prediction site could be more than double that produced by another wind prediction site in the array, even when the two sites are within 5 miles of each other. The wind array power using methods 2-6 varied by 25% based on the different number of wind turbines that are affected by the predicted wind speed at a particular site. These results suggest that one should site wind speed prediction sites so that each prediction site is close to an equal number of wind turbines. This policy of siting wind prediction sites will guarantee that one prediction site, that may experience site specific variations which effect an unknown number of turbine sites, does not cause significant errors in the power predicted to occur from the array.

The development of methods to estimate wind power prediction error is presented in Section 7 of the report. The first method developed assumes the error is time invariant and a zero mean normal process. The prediction error is plotted for 22 sites on the SESAME array and is shown to have zero mean and be time invariant. A statistical test is used to determine whether the error is normally distributed. The results indicate that the prediction error is normal when the prediction of trend wind speed is accurate. This test was performed for both a front and storm front.

A second method for estimating wind power prediction error averages the difference between the actual and predicted wind array power over a 15 or thirty minute period and utilizes this average as an estimate of the wind power 30 minutes or an hour into the future. This wind power error prediction method does not require that the error is zero mean or normal and assumes it is slowly time varying. Moreover, the error estimate is never allowed to become less than 10% of the power since the fact that the error is temporarily small for a short period does not indicate that the error will be small at some future time. The results indicate that the method is accurate in estimating an error band around the predicted trend.

Conclusions of this research project are given in Chapter 8. The unique contributions of the research are highlighted. Recommendations for future research are also given.

JUSTIFICATION AND USE OF WIND POWER PREDICTION IN UNIT
COMMITMENT AND GENERATION CONTROL

An analysis and simulation of wind power variations for square and rectangular arrays [3,16] was recently made based on wind speed measurements and the wind model developed from these wind speed measurements. These results indicate the worst case magnitude of wind power change for passage of meteorological events could be much larger than any utility could cope with and maintain operation. It was shown that the magnitude of wind power changes for passage of meteorological events on a single 350 MW array in a 7000 MW utility can seriously reduce operating reliability and economy by significantly changing the unit commitment, automatic generation control, and economic dispatch schedules and operation. Moreover, it was shown that total array capacity changes can occur within 10 minutes and can occur repeatedly for passage of a front or storm. Finally, it was shown that near total capacity power variations can occur simultaneously on different arrays 20-40 miles apart in the direction of motion of the meteorological event. These results clearly indicate that infrequent meteorological events can cause serious operating problems on single wind turbine arrays with less than 5% penetration. The several 350 MW arrays contemplated in the Pacific Gas and Electric and Southern California Edison systems could cause operating problems for these utilities for the very infrequent occasion that meteorological events occur on these sites. It was also pointed out that there is a need for a modified unit commitment and generation control if wind power penetration exceeds 5%. Penetrations above 5% appear to be feasible as wind technology improves and the installation of large wind turbine arrays increases. A discussion of a modified unit commitment and generation control strategy is given in Subsection 2.3.

The effects of turbulence were shown [16] to be quite large on a single wind turbine but were shown to cause small variation as a percentage of utility capacity for wind turbine array penetrations of 5% on large utilities. The difference in the effects of turbulence and meteorological events in terms of the magnitude of array wind power variations and thus their effect on a utility is due to the fact that:

(1) the weather map fluctuations associated with energy spectrum below 5 cycles/hour are generally correlated between sites in an array and have relatively larger energy than "gusts." The high correlations make the power variations on each wind turbine appear quite similar and thus cause large power variations out of the array;

(2) the turbulence or "gusts" wind speed variation component associated with the spectrum above 5 cycles/hour has less energy than the "weather map fluctuation" component and is generally uncorrelated between sites. The lack of correlation of turbulence between sites generally will cause cancellation of wind variation between the different wind turbine sites which greatly reduces the turbulence induced power variations out of an array.

It is impossible to determine whether there are or are not any meteorological events in the energy spectrum of Figure 1 since information is lost in the calculation of energy spectrum. However, the conclusion that the wind speed variation associated with the energy spectrum below 5 cycles/hour is of concern in operation and control of utilities is valid whether there are meteorological events in this spectrum or not. The validity of the concern is based on the significant energy of these variations and the high correlation between wind turbines in an array for such variation. It will be our custom to refer to weather map fluctuations as meteorological events in our discussion.

2.1 THE UNIT COMMITMENT AND GENERATION CONTROL PROBLEMS

Research performed by Michigan State [17,18] and others [9,10,11] has shown that large wind power variations from an array of wind turbines can cause significant operating problems for a utility. These problems occur because a utility's unit commitment and generation control is based on (1) handling small cyclic load variation rather than the larger cyclic wind power variation and (2) large load trend change can be accurately predicted 24 hours ahead but trend wind cyclic wind power variations have not been predicted accurately. Utility practice for conventional loads, which can be predicted on a 24 hour basis within 2%, has been to connect or commit units in advance using a "unit commitment" schedule, and to control operating units already connected via set point adjustments to unit governors as load varies about the predicted value. Since wind power variations exceed load variations on a percentage basis, this practice must be modified. Fast cyclic and slow trend wind power variations are both large and unpredictable 24 hours ahead of real time. Since wind power variations are usually viewed as negative load to the utility's unit commitment procedures, which provide fast responding generation (load following requirement) and generation reserves (operating reserve), there is a unit commitment problem in providing the proper additional reserves for wind power variations in unit commitment schedules made 24 hours ahead. Trend and cyclic wind power variations due to meteorological events can, for wind penetration levels above normal spinning reserve levels (5% of a utility's capacity), greatly exceed both the systems spinning reserve, unloadable generation and load following capability. This can cause a serious reduction in system reliability and a violation of the utility guidelines for reliable operation (NERC Minimum Criteria for Operating Reliability) [19]. The reduction in operatingg reliability due to large unpredicted wind power variation can be alleviated by increasing the load following and spinning reserve levels thus reducing or completely eliminating the capacity credit allowed to the wind generation capacity.

Two control problems associated with power system operation for wind power variations are:

(1) The utility's automatic generation control will saturate for long periods when the total change in wind generation and a simultaneous load change will require conventional generation change that exceeds load following capability in a ten minute interval. This problem violates NERC performance guidelines [19]. However, it can be eliminated by imposing a farm penetration constraint on the capacity of all wind turbine generators that can be affected by a single thunderstorm front. This
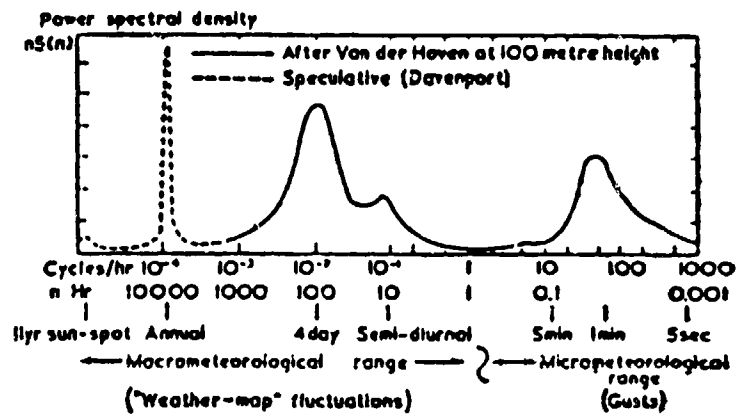
Figure 1. Power spectral density of the wind.

farm constraint, which limits wind generation to be less than the spinning reserve level in a utility, not only can solve this control problem but also would solve the unit commitment problem discussed above.

(2) Steam turbine units will cycle as a result of simultaneous load and generation changes that induce frequency deviations that exceed governor deadband of conventional units. This continual cycling of units is objectionable to generator operators and can cause increased maintenance costs, increased forced outage rates and ultimately reduced unit life. The cycling of nuclear units is of concern for safety reasons in addition to those mentioned above. The cycling problem can occur due to a storm front sweeping through a wind generator array causing large power variations on successive echelons. An echelon penetration constraint on the capacity of all WTGs in a straight line normal to motion of the meteorological event that experience simultaneous wind speed changes will eliminate this cycling problem. The fast cyclic wind variation, which lie in a range between 2.7×10^{-4} hz and 1.6×10^{-3} hz, can be quite large and cannot be eliminated by the echelon penetration constraint because these cyclic variations come from wind variations in a front or storm that affect widely separated echelons or possibly different arrays. The cyclic variations, around trend wind speed variations, can be compensated by increasing the response capability of automatic generation control.

These two control problems, like the unit commitment problem, result from the fact that there are large cyclic and trend wind power variations. The difference between the unit commitment problem and the control problem is one of providing sufficient generation reserves that can respond rapidly enough in the unit commitment and have sufficient control action within the generation controls to properly compensate for fast wind power variation. The farm penetration constraint acts to limit instantaneous maximum wind power increase or decrease so that unit commitment and control can cope with trend and cyclic wind variations.

Three solutions to the unit commitment and generation control problem discussed above can now be explained using Figures 2-4. A hypothetical daily load curve is used for illustration. The diurnal wind generation is shown as a constant and the wind generation variation due to meteorological events is shown as a set of cyclic and ramp variations. The effective load is shown as the difference between the daily load curve and the wind generation. It is met using a unit commitment that starts up and shuts down units to provide sufficient reserves to insure operating reliability. The operating reserve is composed of both nonspinning reserve and spinning reserve. Spinning reserve is generation connected to the system and running, quick start units such as gas or hydro turbines, and all load curtailment capability available to the operator. The nonspinning reserve generation is counted in operating reserve but not in spinning reserve. The operating reserve and spinning reserve for each of these three solutions to the unit commitment and control problem are shown in Figure 2-4. The unloadable generation reserve, also shown in Figures 2-4, is negative reserve that permits backing off conventional generation. Units having unloadable generation reserve are operated above their minimum generation levels so that wind generation increases can be accommodated by reducing conventional generation without

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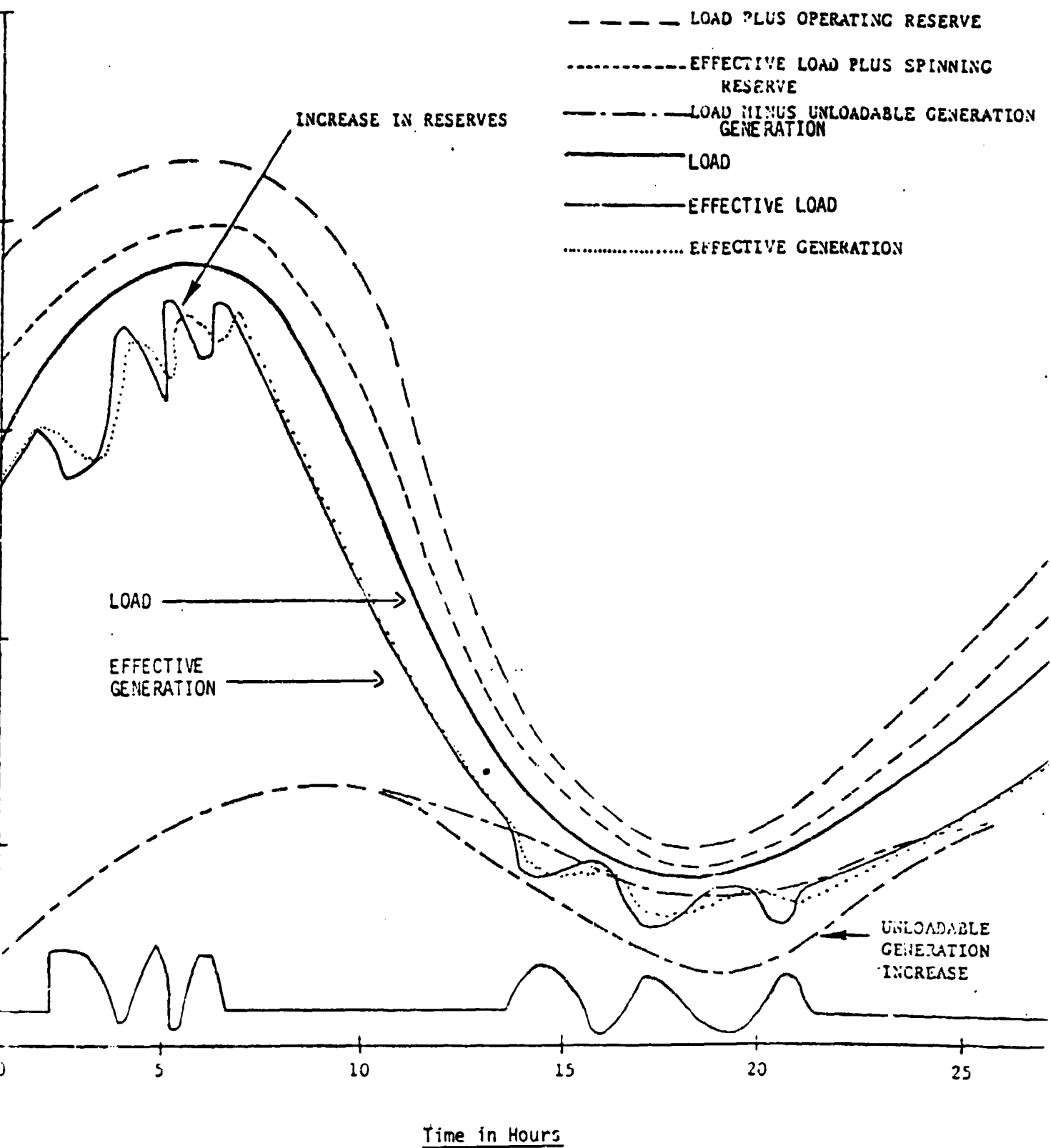
Figure 2. Unit commitment solution that increases operating and spinning reserve by the wind turbine array capability.

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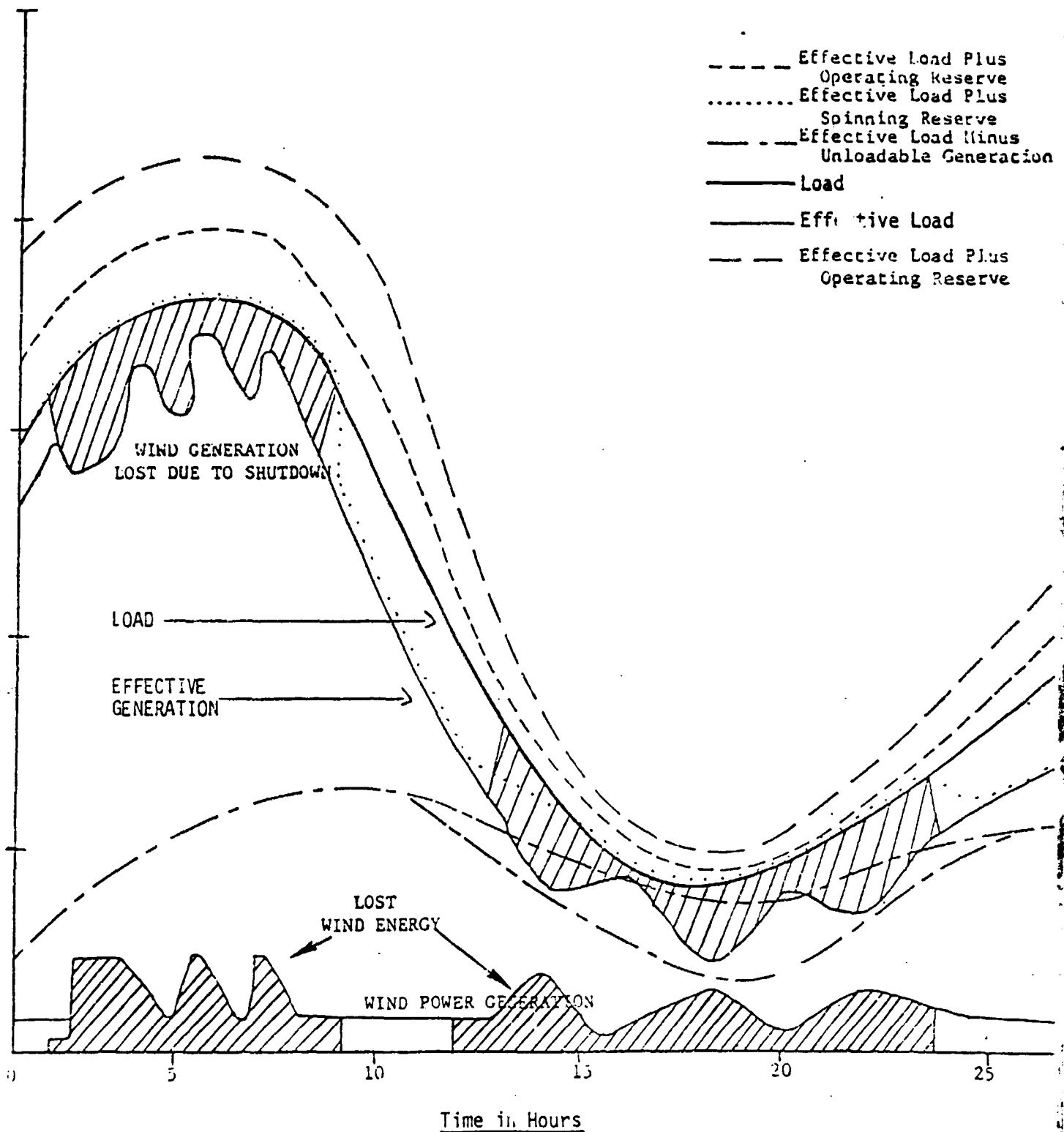
Figure 3. A generation control strategy that shuts down the array
for passage of meteorological event.
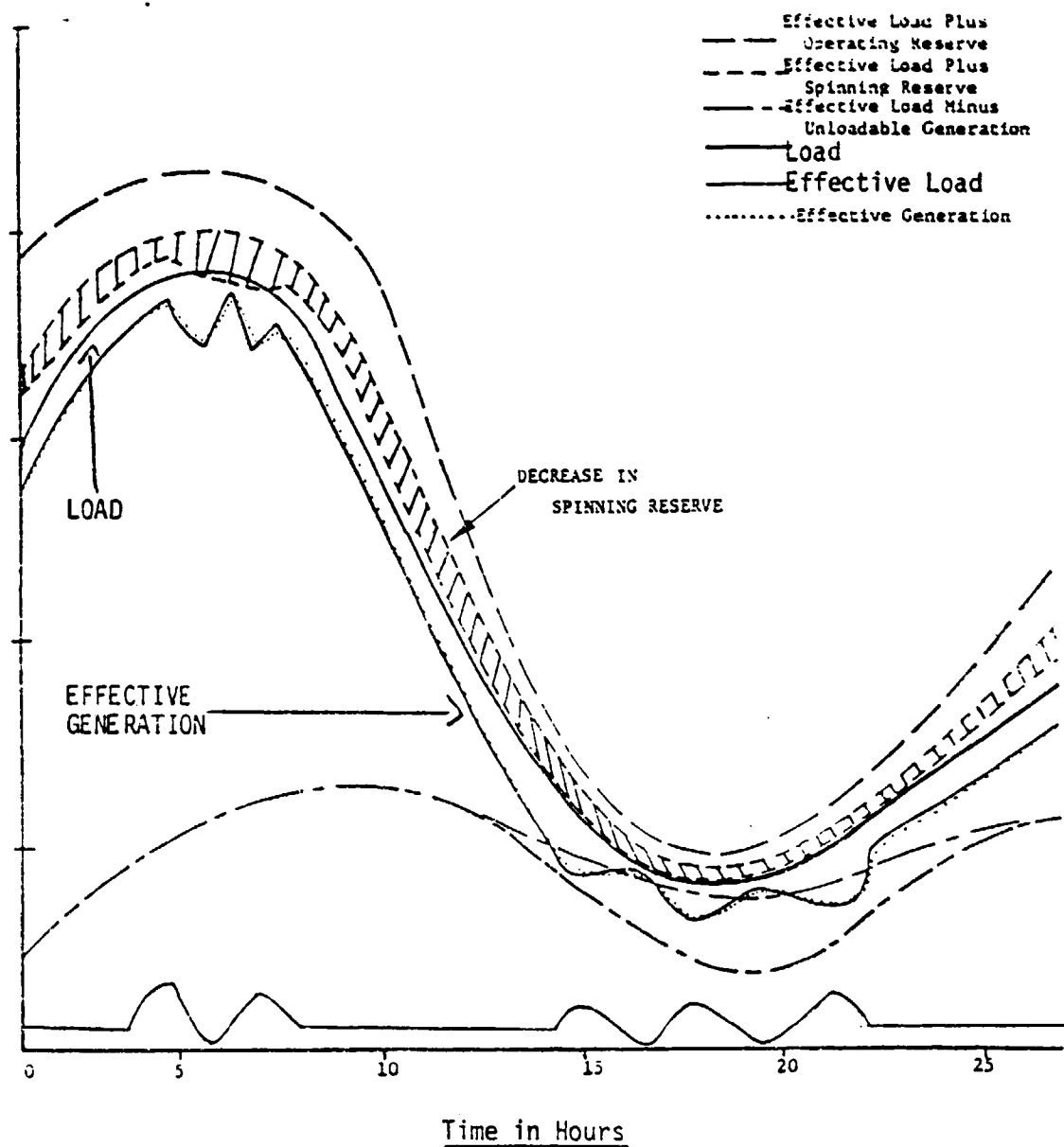
Figure 4. A unit commitment and generation control procedure that adjusts unit commitment and load following generation control capability for wind power variation.

tripping units off line. Unloadable generation reserves are important to preserving operating reliability at times of very low load levels when every base loaded unit remains connected if all can be operated above their minimum generation loads. Unloadable generation reserve places a constraint that indicates these base loaded units must be operated sufficiently above their minimum generation levels so that increases in wind generation can be accommodated without disconnecting these base loaded units.

The automatic generation control (AGC) matches the effective generation to effective load variation and thus keeps area control error and frequency deviations small. The automatic generation control adjusts the generation levels of units under the control so that system generation will match total system load. The automatic generation control is implemented at a utility control center and determines and adjusts the desired generation level of each generating unit in the utility.

The first solution [9], which adds the capacity of the wind turbine array to spinning reserve, unloadable generation and operating reserve, can be observed in Figure 2. Spinning reserve and operating reserve on non-wind generation unit commitment are maintained at levels that totally ignore the presence of the wind generation that reduces the load carried by the units and thus increases system spinning and operating reserve. The unloadable generation level on non-wind generation unit commitment is modified at night when wind generation is available. This allows for wind generation increases that equal the total capacity of all wind turbine arrays in the utility. The unloadable generation reserve level, shown in Figure 1, is so large at other times of the day that the need to accommodate wind generation increases places no constraint on the non-wind generation unit commitment. The effective generation curve shows that automatic generation control response set without consideration of wind generation variation cannot effectively track effective load changes during passage of meteorological events. Under these conditions, large frequency and area control error deviations occur during passage of meteorological events that would continually violate NERC Minimum Criteria for Operating Reliability [19]. No adjustment to automatic generation control to increase response rate capability was discussed in this solution and so none is indicated in Figure 2. The spinning reserve and operating reserve levels in this solution to the unit commitment are large. The wind generation is added to the spinning and operating reserve levels that would have existed if the generation were not present. This solution [9] would give no capacity credit to wind generation in meeting load and would require that fuel be consumed and operating staffs be maintained for all generating units that would have operated if the wind generation was not available. This results in commitment of additional units and thus in increased fuel and maintenance costs than would be necessary if operating reserve were adjusted in accordance with wind generation changes. Additions to wind generation capacity must be justified based on displacement of fuel which requires that wind technology be capable of producing energy at a 30 year levelized cost of 3¢/kWh. Allowing capacity credits to wind generation by minimizingg the increase in load following and spinning reserve in Solutions 2 and 4, will greatly reduce the economic breakeven price for wind technology.

The second solution [2] would alleviate the large area control error and frequency deviations by shutting down the wind turbine arrays during the

passage of meteorological events. The ramp and cyclic variations have been shown to be as large as the capacity of all wind turbine arrays, occur in as short a period as 10 minutes and possibly cycle with periods of 20 minutes to an hour or more. A utility's automatic generation control must attempt to track such variations in order to keep tie lines at prescheduled power flow levels. The power flow on tie lines is maintained at prescheduled power flow levels to assure that there is sufficient power flow capability to supply the inadvertant power for loss of generation contingencies. The solution to shutdown the wind turbine arrays during passage of all meteorological events does not appear attractive since the wind energy would be lost due to shutdown of the array. If accurate prediction of wind power variations for meteorological events can be made, the shutdown of the wind turbine arrays and the concommitant loss of wind energy can be avoided

(1) entirely for fronts since the trend wind power variation is accurately predicted and the cyclic wind power variation with period of 1-60 minutes is not large;

(2) in part for storms and thunderstorms since the time of arrival and departure can be accurately predicted and thus the shutdown of the array for long periods before and after the storm may be avoided.

The simulation of power from wind turbine arrays that experience severe storm and thunderstorm induced wind power variations indicate almost simultaneous shutdown of all units in an array due to high speed or low speed shutdown logic. The wind turbine units in the array will all startup and very quickly reach rated array power levels. This shutdown and startup can be experienced several times as storm cells pass through the array. The shutdown of the array for the entire period of storm cell activity may be desirable for some utilities that would wish to avoid attempting to compensate for the repeated shutdown and startup of the array using automatic generation control and feedforward control of fast responding hydro, diesel, and gas turbines.

This solution [2] of shutting down the arrays for meteorological events did not consider the use of wind power prediction to minimize or eliminate the need for such shutdown. The shutdown of the wind turbine array was proposed as a method of reducing the control problem of compensating for large wind power changes as shown in Figure 3. This second solution does not address the unit commitment problem.

The third solution proposed in [18] addressed both the unit commitment and control problem (utilizing no prediction of wind power variation) by limiting wind power variation via the farm and echelon penetration constraints mentioned earlier. The satisfaction of the farm penetration constraint can be observed in smaller levels of wind generation and variation in Figure 4. The result is a modification of spinning reserve and unloadable generation to track effective load and to increase these reserves during passage of meteorological events as shown in Figure 4. Operating reserve modification with wind generation change was not discussed in this study [18] and thus no modification from that utilized, when no wind generation is present, is shown in Figure 4. Unloadable generation may be slightly increased in this solution due to wind generation but not equal to the capacity of all wind turbine arrays as in the previous solutions discussed. The increase in unloadable

generation would occur if the maximum increase in wind generation exceeded maximum first contingency loss of export or load which would violate the farm penetration constraint. If the farm penetration constraints were satisfied, an increase in unloadable generation would only be needed during meteorological events. Spinning reserve would not be increased by the capacity of the array as in previous solutions. Spinning reserve would not increase significantly if the farm penetration constraint were satisfied.

The increase in spinning reserve due to wind generation would then only be large enough to insure reliable operation for the continual large power variations observed for passage of meteorological events. This increase in spinning reserve can be observed in Figure 4. Note also the step change in spinning reserve lags the step change in wind power output due to a change in the wind speed in the array. The step change in spinning reserve is delayed from the change in wind speed in order to permit confirmation of apriori wind speed forecasts that the change in wind speed will be maintained over the next few hours. The reduction in spinning reserve and unloadable generation reserve over that in the previous solutions will significantly reduce fuel and operating costs. The automatic generation control will not adequately track the ramp and cyclic variations due to passage of meteorological events although significant reduction in area control error and frequency deviation is possible by (1) the addition of load following and spinning reserve capability to unit commitment during passage of meteorological events and (2) increasing automatic generation control response and response rate capability through adjustment of AGC control parameters to exploit these additional reserves supplied by unit commitment. Methods for deciding the additions to spinning reserve, unloadable generation, and load following reserves for continual large wind power variation was very briefly discussed in [18]. No detailed procedures were given for determining the magnitude and duration of these reserve additions for both unit commitment and for generation control.

2.2 A MODIFIED UNIT COMMITMENT AND GENERATION CONTROL STRATEGY

Utilities have developed unit commitment programs that can determine which units should be connected during each hour of predicted load increase and which units should be disconnected during periods of predicted load decrease. The selection of the units to be connected and generating or disconnected as well as the ordering of the units to be connected or disconnected within each hour is based on minimizing fuel costs and startup and shutdown costs while satisfying constraints on the minimum length of time a unit should remain connected or disconnected, minimum and maximum generation levels for each unit, etc.

The unit commitment procedure can accurately and economically schedule the connection and disconnection of generating units 24 hours ahead because the load demand can be accurately predicted (within 2%) 24 hours ahead. Utilities must limit total wind generation capacity to be less than the minimum spinning reserve and unloadable generation levels if the wind power is not predicted. The spinning reserve and unloadable generation reserve is intended to provide the reserves for loss of generation or export contingencies and errors in predicting load variation. If wind power variation is not predicted 24 hours ahead, one must consider that the wind power is not available in scheduling non-wind generation to assure that proper

levels of operating reliability are maintained since wind power levels of the array are not constant or follow a consistent pattern over every 24 hour period. Thus, the procedures in solutions one to three that either add wind generation levels to spinning reserve and operating reserve or limit the wind generation capacity to be less than the minimum of spinning reserve and unloadable generation reserves is required to maintain operating reliability if wind power prediction is not undertaken. Increasing spinning reserve and operating reserve by the wind generation capacity gives wind generation no capacity credit and thus the wind generation would not be counted as serving any portion of the customers load. The only economic benefits for installing wind would thus be the value of the fuel replacement on conventional units due to wind generation, which requires high fuel costs to justify installation of wind generation or reduction in the 30 year levelized cost of wind energy to $3¢$/kWh. The third solution, limiting wind generation capacity to be less than the minimum of spinning reserve and unloadable generation, would decrease connected generation in proportion to the magnitude of the wind generation and may only slightly increase spinning reserve levels during periods when the array is experiencing passage of meteorological events. The operating reserve may be decreased by the capacity credit (8%-30%) of wind array capacity assigned to the wind generation although no credit was given in Figure 4 or discussed in the research [18] where this solution was proposed. This third solution has three major disadvantages:

(1) the wind generation capacity is limited to the load following capability provided by the unit commitment and generation control;

(2) a possible reduction in possible operating reliability by utilizing spinning reserve and unloadable generation reserve, which is intended to cover loss of generation or export contingencies and error in load prediction, to cover the wind power variation out of all wind turbine arrays;

(3) very little (0%-30%) reduction in operating reserve.

A modified unit commitment procedure that would update the 24 unit commitment every quarter hour based on one or more hour ahead prediction and 24 hour ahead forecast of wind power variation could overcome all of these disadvantages and allow large wind generation penetrations.

The 24 hour ahead unit commitment schedule would be developed based on the 24 hour ahead prediction of load and a 24 hour ahead forecast of wind power variation. Methods for forecasting wind power [6] 24 hours ahead could accurately estimate diurnal wind power variations. The methods developed in [6], however, could not accurately estimate meteorological event induced changes.

A major modificaton of the 24 hour ahead unit commitment was proposed in [3] that would update the 24 hour unit commitment utilizing a one or more hour ahead prediction of wind power variation. The predicted trend wind power and the error in this wind power prediction would be predicted for one or more hours ahead of real time. The predicted wind power will be shown to accurately capture the trend change in wind power variation due to fronts, storms, thunderstorms, or stationary highs. The error in the wind power

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prediction will be shown in Section 7 to be at least 10% for fronts and stationary highs and could be as large as 100% of the wind turbine array capacity during storms and thunderstorms. Although the trend change over one or more hours in wind power due to the storm front can be predicted, the very large cyclic wind power variations due to passage of individual storm or thunderstorm cells through wind turbine clusters cannot be predicted one hour ahead since their formation changes over time, and movement was shown to be erratic. The large cyclic variation in these storm cells do not appear to be highly correlated between sites that experience the same storm cell and thus prediction appears to be difficult if not impossible. The estimation of an error band around the hour ahead trend wind power prediction does appear feasible from results in Section 7 and is essential in order to compute the operating reserve, spinning reserve, unloadable generation reserve, and load following capability to be provided within the quarter hour unit commitment. Since load power prediction error 24 hours ahead is far smaller (2%) than the levels of spinning reserve and load following capability in the 24 hour unit commitment schedules for utilities without wind penetration, the error in load power prediction is often ignored in setting spinning reserve levels in a particular utility even though NERC guidelines for operating reliability indicates spinning reserve levels can be increased based on errors in load prediction. Since the error for wind power prediction is at least 10% for fronts and stationary high and can be 100% for storms or thunderstorms, operating reserve, spinning reserve, unloadable generation reserve, and load following capability should all be adjusted within the quarter hour updated unit commitment based on the changes in the wind power prediction error that are predicted to occur. These reserve levels should be adjusted directly proportional to the size of this wind power prediction error level, which reflects (1) the bias in predicting trend wind power variation over an hour, (2) the effects of turbulence (wind power variations with periods of less than 10 minutes), and (3) meteorological event (front, stationary high, storm, thunderstorm) induced cyclic variation with periods of less than an hour. The operating reserve and spinning reserve would thus be adjusted based on the predicted trend minus the trend error variation since one must be prepared to commit non-wind generation capacity based on the lowest predicted level of wind generation. The unloadable generation reserve would be adjusted based on the predicted trend plus the trend error variation since one must be prepared to disconnect non-wind generation or dump wind generation during periods of light load, when all non-wind generating units are at or near their minimum capacity levels, based on the maximum predicted level of wind generation.

The quarter hour updated unit commitment, that utilizes this one or more hour ahead prediction of wind power and error in wind power prediction, would allow (1) increased wind power penetration, (2) adjustment of spinning reserve, unloadable generation, and load following within the unit commitment based on both the wind power prediction and its error, and (3) adjustment of operating reserve in proportion to predicted wind generation and predicted wind generation error as shown in Figure 5.

The quarter hour updated unit commitment would schedule connection and disconnection of peaking, regulating, and economic units that are available to be connected or disconnected over the hour prediction interval. The quarter
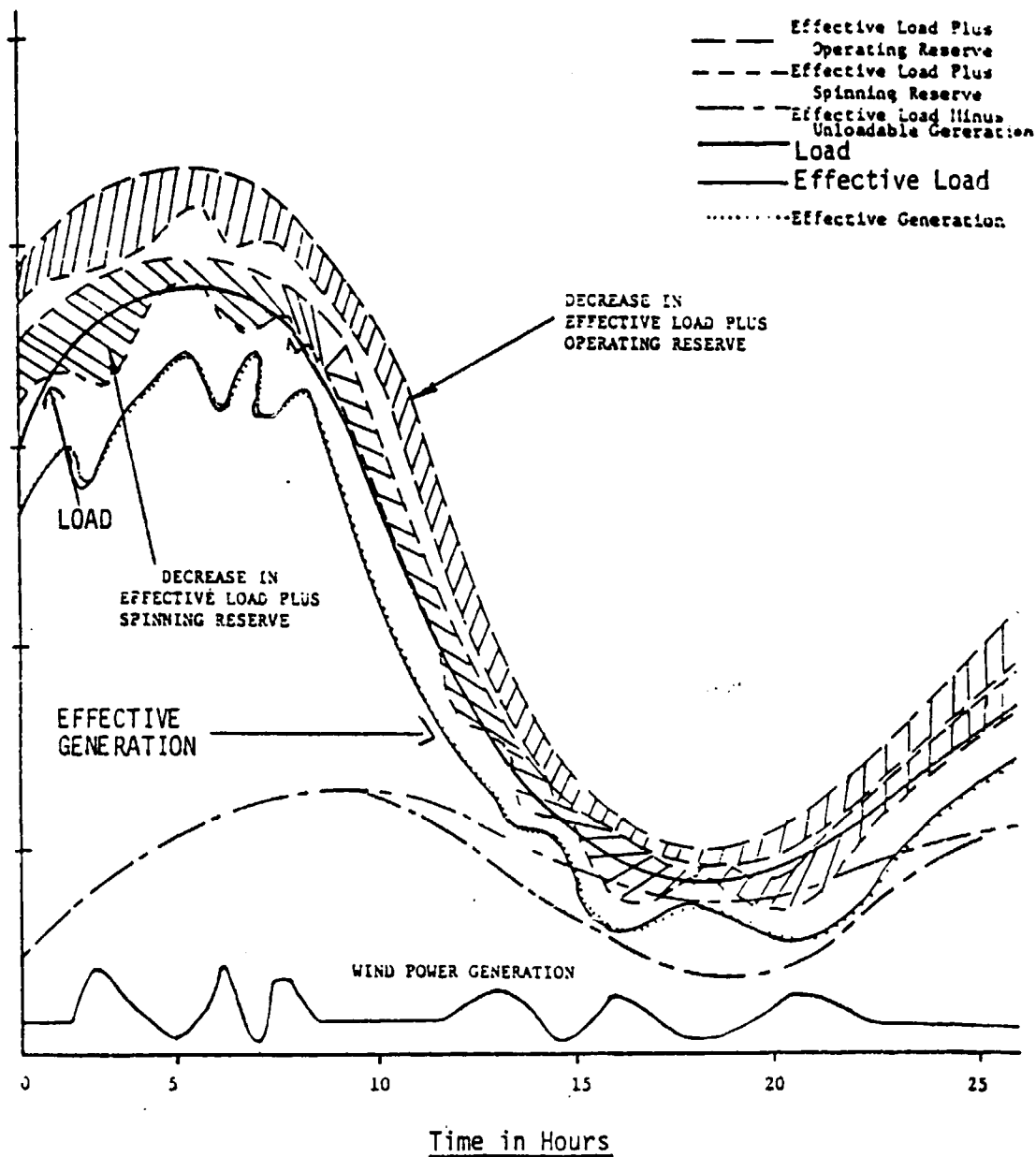
Figure 5. A modified unit commitment and generation control procedure that utilized predicted wind power variation to adjust unit commitment and load following generation control capability.

hour updated unit commitment would also connect quick pickup units (hydro and gas turbine, and diesels) in order to supply the load following capability required above that in the units under automatic generation control to cover the predicted load minus wind power change over the next hour. The quarter hour unit commitment will attempt to keep the quick pickup units in spinning reserve by either not allowing them to be heavily loaded if connected or by keeping them disconnected in order to cover the unexpected wind power changes reflected in the wind power prediction error. The quick pickup units may be connected and loaded in 15 minutes to cover wind power variations when these variations cause the actual wind power to be less than the predicted trend wind power. The quarter hour unit commitment would then connect peaking, regulating or economic units on standby in order to unload quick pickup units if the constraints on minimum shutdown or operating time on these units are satisfied. The economic peaking, and regulating units may also be connected or disconnected in response to predicted trend wind power variation. Interruptible load would not be disconnected if quick pickup and the standby economic, peaking, and regulating units along with wind turbine array control can supply the load following capability needed. Interruptible load will be counted as part of spinning reserve along with disconnected or connected but unloaded quick pickup units. Inclusion of interruptible load and quick pickup in spinning reserve is common in Europe but generally has not been practiced in the NERC procedures. Since interruptible load can be disconnected and quick pickup can be connected and loaded in 15 minutes, they can be available when needed with a 15 minute prediction interval thus satisfying the requirements derived of spinning reserve.

The hour ahead prediction interval for trend and the error in predicting this trend wind power variation is required since it takes at least one hour to connect the peaking, regulation, and standby economic units that are available to the quarter hour updated unit commitment. The quarter hour update interval for this quarter hour updated unit commitment is chosen so that quick pickup units can be connected with no more than a fifteen minute delay. NERC guidelines, that require mismatch in generation and load be alleviated in 10 to 15 minutes, could thus be satisfied. The hour ahead prediction interval for trend wind power prediction error is also required to permit the preparation of peaking, regulation, and standby economic units so they could be connected to replace quick pickup units, that are connected, and disconnected in response to actual wind power prediction error. These quick pickup units that are connected would be controlled to compensate for the variation in wind power and would be disconnected as the regulating, peaking, and economic units prepared based on the hour ahead trend and trend error prediction were connected to replace them and perform the generation control function. Unloading quick pickup units increases spinning reserve and makes the quick pickup units available to compensate for the error in wind power prediction in the next hour.

The solution to the control problem proposed in this research should only be concerned with the fast trend and cyclic components of wind power variation because the slow trend (diurnal) wind component can be accurately predicted and handled as the slow trend load component via normal 24 hour unit commitment and economic dispatch. The control solution proposes to utilize:

(a) automatic generation control that would better track the hour ahead

predicted trend up to a prespecified limit;

(b) a supplementary automatic generation control of the peaking, regulating, quick pickup units committed by the quarter-hour updated unit commitment to respond to the predicted trend and cyclic variation. These units have a fast response that either is not utilized fully or is not included in present automatic generation control strategies. This is called feedforward generation control in [8];

(c) a coordinated blade pitch control on all wind turbines in single or multiple arrays that can clip predicted cyclic wind power variation and smooth rapid hour ahead predicted trend changes that cannot be easily handled by automatic generation control or the feedforward generation control. This is called feedback array control in [8].

The coordination of these three controls would be permitted through the hour ahead prediction of trend and quarter-hour ahead prediction of cyclic wind power variation. The modified generation control has more than ample control capability for tracking the very large cyclic and trend variation which could be expected when wind penetrations range from 5-15% of a utility's capacity.

2.3 OPERATING RESERVE REQUIREMENTS ON UNIT COMMITMENT

The purpose of the operating reserve, as stated in its definition in the NERC Minimum Criteria for Operating Reliability [19], is to provide sufficient reserve above firm system load to provide for: regulation within the hour to cover minute to minute variations (load or generation), load forecasting error, loss of equipment (generation or transmissions), and local area protection. The operating reserve is set for each hour and the system unit commitment is required to provide this required level of operating reserve for each hour of the day. The operating reserve can be split into spinning and nonspinning reserve components.

The specific operating reserve level OR_k for each hour must be provided by either units presently committed to base, economic dispatch or regulation functions or by quick pickup units such as gas turbines, diesels, hydro, pumped storage, battery, or other short term storage alternatives. The total operating reserve must be distributed throughout the utility so that each local area is adequately protected for contingencies such as loss of generation or transmission. A constraint [21] on power system economic dispatch and unit commitment at each hour k that incorporates the above considerations is:

$$I(k) + QP(k) + \sum_i \min\{DC_i - P_i(k); MOR_i\} \geq OR(k)$$

I(k)   the capacity of interruptible load via contract with the customer

QP(k)   capacity of all quick pickup and storage that could be brought on line and used within 10-60 minutes at hour k

OR(k)   the operating reserve requirement set based on reliability method for hour k

$P_i(k)$ the generation level of unit i at hour k

DC_i the desired capacity of unit i

MOR_i the maximum operating reserve allowed on unit i

The utility has alternatives that could increase operating reserves if the above constraints were violated and the system was considered in an emergency condition. The values of DC_i and MOR_i could be increased, voltage reduction, public appeal via radio and television to limit use, and load shedding could all be used to increase the operating reserve. The latter three methods of reducing load are of increasing severity and are not utilized without care due to their consequences.

The effects of large wind generation capacity on the prediction of hourly operating reserve capacity over a 24-hour period can be quite large. The methods [22] used to incorporate wind power generation require prediction of wind power averages for each hour of the day based on hourly wind speed average measured at a single site. The predicted wind power record is then used to determine the load that must be served by conventional generation. This load minus the slow trend in wind generation can be used to determine a load duration curve and the operating reserve required to maintain LOLP below a certain level.

This procedure is quite satisfactory for setting operating reserve and OR(k) for slow trend and diurnal wind power variations and load variations that can be predicted 24 hours ahead and are repeated on a daily cycle with minor variations. If this procedure was used in solutions 1-3 for the commitment problem, the operating reserve would have been reduced in proportion to wind generation over the 24 hour period.

The above procedure could not be used in the quarter-hourly updated unit commitment because it would not allow quarter-hourly update of the operating reserve level based on the magnitude of both the load and the fast trend and cyclic wind power variations due to significant changes in wind speed for passage of meteorological events. If the effects of fast trend and cyclic variations were included in this method, the operating reserve levels calculated would effectively ignore wind generation and add the wind turbine array capacity to operating reserve [9]. This is exactly what was indicated in the first three solutions proposed for the unit commitment problem in Section 1.

It should be noted that the wind power record from a single wind turbine used in [9] was much more oscillatory than out of an array due to large effects of turbulence. The large turbulence induced variation on a single wind turbine are uncorrelated between wind turbines and thus are averaged out in the total power from an array and are small [3]. The large oscillations in the wind power record used in [9] could be viewed as occurring from meteorological events based on results in [3]. The results in [9] then indicate that the wind power generation can be ignored if the above [22] method is used to set operating reserves for wind variations that include passage of meteorological events. The operating reserve was set ignoring wind

power generation in Figures 2-4. However, the meteorological events shown in Figures 2-4 occur only twice; during the late afternoon peak in load and during the night time low. There is an average wind generation level that would reduce OR(k) in the 24 hour unit commitment using the procedure [22] described above. Thus, the effects of average wind power on OR(k) in the 24 hour unit commitment do not appear in Figures 2-4.

The above procedure may at times reduce OR(k) above load L(t) from the values shown in Figures 2-4 but would allow operating reserve to instantly and proportionately increase with increasing wind generation and vice versa. Operating reserve OR(k + j/4) in the quarter-hourly unit commitment should change with significant changes in wind speed or passage of meteorological events as shown in Figure 5 to reflect changes in effective load L(t) - W(t) and the variability of wind prediction W(t) for passage of meteorological events. No method exists at present that can properly determine proportional changes in operating reserve level OR(k + j/4) in the quarter-hourly update unit commitment for significant changes in wind speed or passage of meteorological events. The transient operating reserve model [24] appears to be a promising approach to properly adjusting operating reserve levels if a markov state model could be determined for trend and cyclic wind variations that utilize statistics obtained from the 1 hour ahead prediction of trend and cyclic wind power variations.

2.4 SPINNING RESERVE, UNLOADABLE GENERATION, AND LOAD FOLLOWING REQUIREMENTS IN THE MODIFIED UNIT COMMITMENT

Spinning reserve, unloadable generation reserve, and load following reserve requirements are discussed in this section.

The spinning reserve, unloadable generation, and load following requirements include a trend and a cyclic component based on the hour ahead prediction of trend and trend error of wind power variation. The spinning reserve SR(k), unloadable generation UG(k) and load following reserve requirements are set based on the following formulas:

$$SR(k) = \max\{D_R(k) + (L_{k+1} - L_k)T + Q^+_{Wk} - (W_{k+1} - W_k)T + Q^+_{Wk}; \ 0\} \qquad (1)$$

$$UG(k) = \max\{D_C(k) - (L_{k+1} - L_k)T + Q^-_{Lk} + (W_{k+1} - W_k)T + Q^-_{Wk}; \ 0\} \qquad (2)$$

$$LF(k) = \max\{UG(k), \ SR(k)\} \qquad (3)$$

$D_R(k), (D_C(k))$ the maximum first contingency loss of reserve (commitment) or increase (decrease) in wind generation at hour k (megawatts)

L_k the 24-hour ahead predicted load at hour k (megawatts)

W_{k+1} the hour ahead predicted trend wind generation at hour k+1 made at hour k (megawatts)

T .1667 hours/hours - fraction of an hour

$(L_{k+1} - L_k) - (W_{k+1} - W_k)T$

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the predicted effective load change in ten minutes during (k, k+1) (megawatts)

Q_{Lk}^+, Q_{Lk}^- the effects of load forecasting error and minute by minute load variation above (below) trend load variation that requires regulation (megawatts)

Q_{Wk}^+, Q_{Wk}^- the effect of trend wind power forecasting error, turbulence, and meteorological events below (above) the predicted trend $(W_{k+1} - W_k)T + W_k$ (megawatts)

The unit commitment can meet these spinning reserve, unloadable generation, and load following requirements through components from each generator connected, quick pickup units and interruptible load. The constraints on unit commitment for spinning reserve, unloadable generation, and load following are:

$$\alpha_k I(k) + \beta_k QP(k) + \sum_{i \in A} \min\{DC_i - P_i(k), MSR_i\} > SR(k) \tag{4}$$

$I(k)$ the capacity of interruptible load via contract with the customer at hour k (megawatts)

$QP(k)$ the capacity of all quick pickup and storage that could be brought on line in 10-60 minutes (megawatts)

A set of generators connected to the transmission grid

α_k percentage of interruptible load counted in spinning reserve at hour k

β_k percentage of quick pickup capacity in operating reserve counted in spinning reserve at hour k

DC_i desired maximum generation level of unit i (megawatts)

$P_i(k)$ generation level of generator i at hour k (megawatts)

MSR_i maximum spinning reserve level allowed on unit i (megawatts)

$$\xi_k I(k) + \gamma_k QP(k) + \sum_{i \in A} \min(P_i(k) - MC_i; MUG_i) > UG(k) \tag{5}$$

$\xi_k = 1 - \alpha_k$ percentage of interruptible load actually interrupted at hour k

$\gamma_k = 1 - \beta_k$ percentage of quick pickup capacity that could be unloaded at hour k

MC_i minimum desired generation level on generator i (megawatts)

MUG_i maximum unloadable generation allowed on unit i (megawatts)

$$\sum_{i \in A} 10 R_i P_i(k) > LF(k) \qquad (6)$$

R_i rate of response in MW/min of generator i

Note that these constraints allow use of quick pickup and interruptible load to be counted in spinning reserve and unloadable generation as required in quarter-hourly updated unit commitment. The expressions for setting (1,2,3) and meeting (4,5,6) spinning reserve, unloadable generation and load following are based on hourly updates (k) because such updates are those for the normal 24 hour unit commitment. The variables such as L_k, W_k, Q_{Wk} etc. in (1,2,3) must be specified every hour. These same expressions (1,2,3,4,5,6) will be used for setting and meeting spinning reserve, unloadable generation and load following requirements in the quarter hour $(k + j/4; \; j = 0,1,2,3)$ updated unit commitment.

2.5 COMPUTATION, JUSTIFICATION, AND UPDATE OF SPINNING RESERVE, UNLOADABLE GENERATION, AND LOAD FOLLOWING REQUIREMENTS QUARTER-HOUR UNIT COMMITMENTS

The quarter-hourly updated unit commitment requires setting W_{k+1}, W_k, Q_{Wk}^+, Q_{Wk}^- at quarter-hourly intervals in order to set $SR(k + j/4 - 1)$, $UG(k + j/4 - 1)$ and $LF(k + j/4 - 1)$ in (1), (2), and (3) for constraints (4), (5), and (6) respectively. The constants $W_{k+1} = W(k + j/4)$, $W_k = W(k + j/4 - 1)$, $Q_{Wk}^+ = Q_W^+(k + j/4 - 1)$ and $Q_{Wk}^- = Q_W^-(k + j/4 - 1)$ since the levels over $(k + j/4 - 1), k + j)$ must be decided on at $k + j/4 - 1$ based on a prediction record of wind power variation $W_1(t)$ for $t \in (k + j/4 - 1, k + j/4)$. Spinning reserve, unloadable generation, and load following levels are likewise updated at $k + \dfrac{j+1}{4} - 1$ to cover the period $(k + \dfrac{j+1}{4} - 1), k + \dfrac{j+1}{4})$ for the quarter hour updated unit commitment computed at $k + \dfrac{j+1}{4} - 1$ for any $k = 1,2,...,24$, $j = 0,1,2,3$.

The measures $W(k + j/4 - 1)$, $W(k + j/4)$, $Q_W^+(k + j/4 - 1)$ and $Q_W^-(k + j/4 - 1)$ used in setting spinning reserve (1) and unloadable generation (2) can be illustrated in part by Figures 6 and 7a. In Figure 6, the load $L(t)$ is constant and shows no variation. The wind variation is represented by a ramp increase over 5 hours leveling off to a constant level. There is no error in predicting cyclic or trend wind power variation and no cyclic wind or load variation so that $\hat{Q}_W^+(k + j/4 - 1)$, $\bar{Q}_W(k + j/4 - 1)$, $\hat{Q}_L^+(k + j/4 - 1)$, $Q_L^-(k + j/4 - 1)$ are zero. The effective load to be coved with by conventional steam generation is also shown in Figure 6. The basic spinning reserve level is D_R, where D_R is the maximum first contingency loss of generation reserve component that is shown as a dotted line that tracks the variation in $L(t)$. The actual adjustment of total connected generation capacity $P_M(t) = L(t) + D_R$ is not continuous but occurs at discrete times, which is indicated by the staircase. The spinning reserve formula reflects this staircase effect by requiring unit commitment supplied capacity to always provide the basic reserve D_R plus the change in $L(t) - W(t)$ over ten minutes; i.e.,
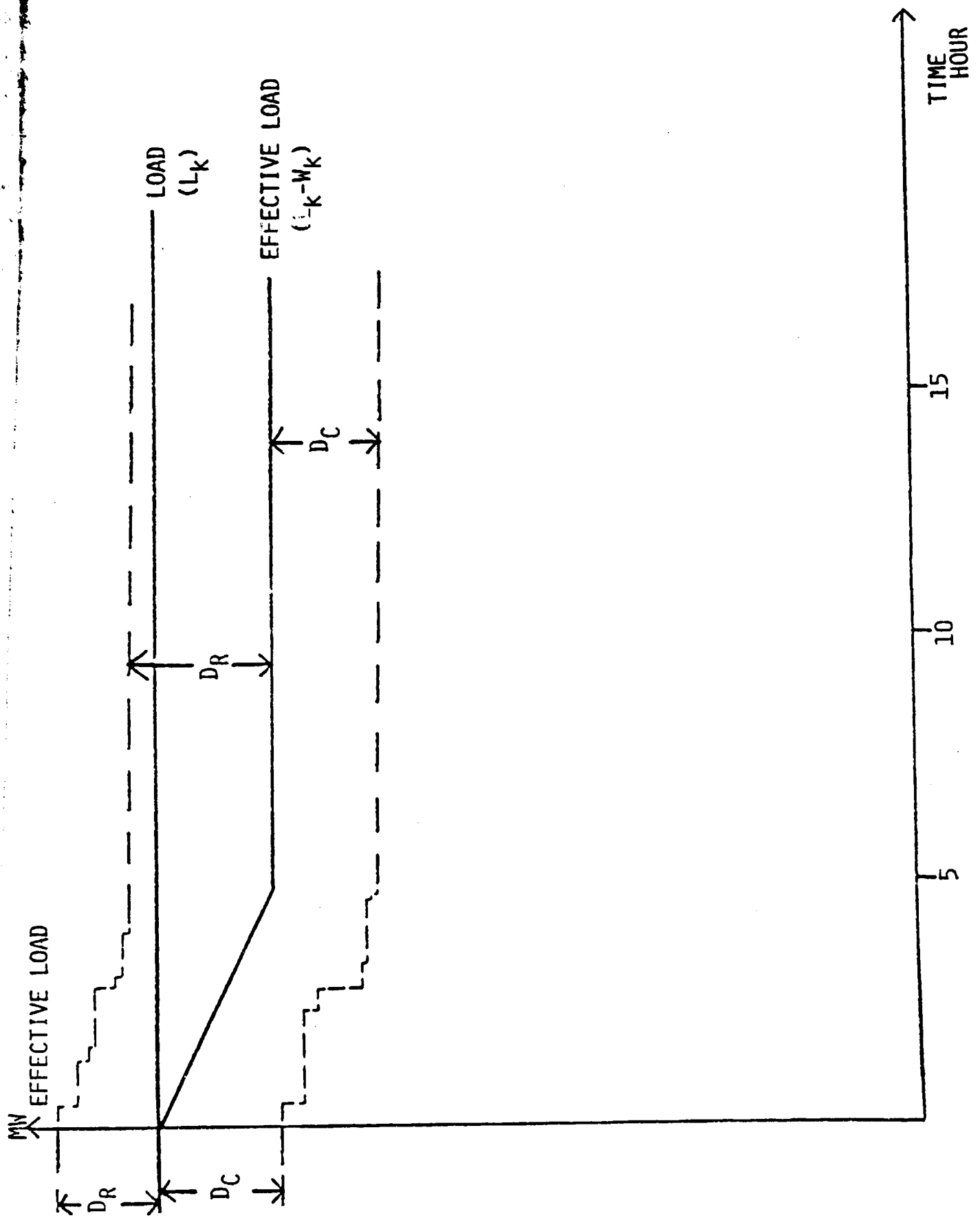
Figure 6. Spinning reserve and unloadable generation requirements for trend wind power variation.

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$$D_R + [(L_k - W_{k+j/4}) - L_{k-1} - W_{k+j/4-1})]T$$

$$W(t) = W_{k+j/4-1} + (W_{k+j/4} - W_{k+j/4-1})(t - [k + j/4 - 1])$$

$$L(t) = L_k + (L_{k-1} - L_k)(t - k)$$

$$k + j/4 - 1 \leq t \leq k + j/4$$

The unloadable generation is seen as negative reserve in Figure 6. The basic reserve level is D_C, which is the maximum of the maximum first contingency loss of load or export from the utility or the maximum first contingency increase in wind generation. The unloadable generation formula (2) again reflects the need for the basic unloadable generation reserve minus the projected change in effective load in ten minutes, i.e., $D_C - [(L_k - W_{k+j/4} - (L_{k-1} - W_{k+j/4-1})]T$. The unloadable generation changes again change in a staircase reflecting discrete time unit commitment changes that always supply at least the unloadable generation in the formula (2).

Figure 7a is identical to Figure 6 except that large cyclic wind variations are imposed on $L(t) - W(t)$. Note then an additional spinning reserve $Q_W^+(k + j/4 - 1)$ and unloadable generation reserve $Q_W^-(k + j/4 - 1)$ are required for $j = 0,1,2,3$ and for k as long as the cyclic variation persists. Note that as the cyclic variation or error in the predicted trend increases, the values of $Q_W^+(k + j/4 - 1)$ and $Q_W^-(k + j/4 - 1)$ increase also.

The methods for predicting trend wind power variation $W(t)$ one hour ahead at $t = k + j/4$ based on measurements at $t = k + j/4 - 1$ are discussed in Sections 5 and 6 of this report. Procedures for predicting the error $Q_W^+(k + j/4 - 1)$ and $Q_W^-(k + j/4 - 1)$ were developed in Section 7 of the report. The most satisfactory procedures averages the error between the predicted power $W(t)$ and the actual wind power $P_W(t)$ over an interval $[k + j/4 - 1 - T, k + j/4 - 1]$ just before $k + j/4 - 1$ and utilize this error as a prediction of the wind power error at $t = k + j/4$. A lower limit on this error would prevent the predicted error from becoming smaller than this limit. This limit would be set based on weather forecasts. This limit would be increased during storms or thunderstorms and would be considerably smaller during fronts, stationary high, or non-event wind conditions.

The predicted power $W(k + j/4 - 1)$ lower limit $W(k + j/4 - 1) - Q_W^+(k + j/4 - 1)$, and upper limit $W(k + j/4 - 1) + Q_W^-(k + j/4 - 1)$ at $t = k + j/4 - 1 - T$ based on measurements at $t = k + j/4 - 1$ are plotted in Figures 8a and 8b. The results in both figures are based on simulations on wind power at 81 wind turbines sited at a density of $1/\text{mile}^2$. The wind power was simulated based on a predicted wind speed record at a site in the array and based on the actual measured wind speed at the site. The predicted trend and predicted error in Figure 8a was for a front and the predicted trend and trend error in Figure 8b was for a storm front. These results show that the lower limit was
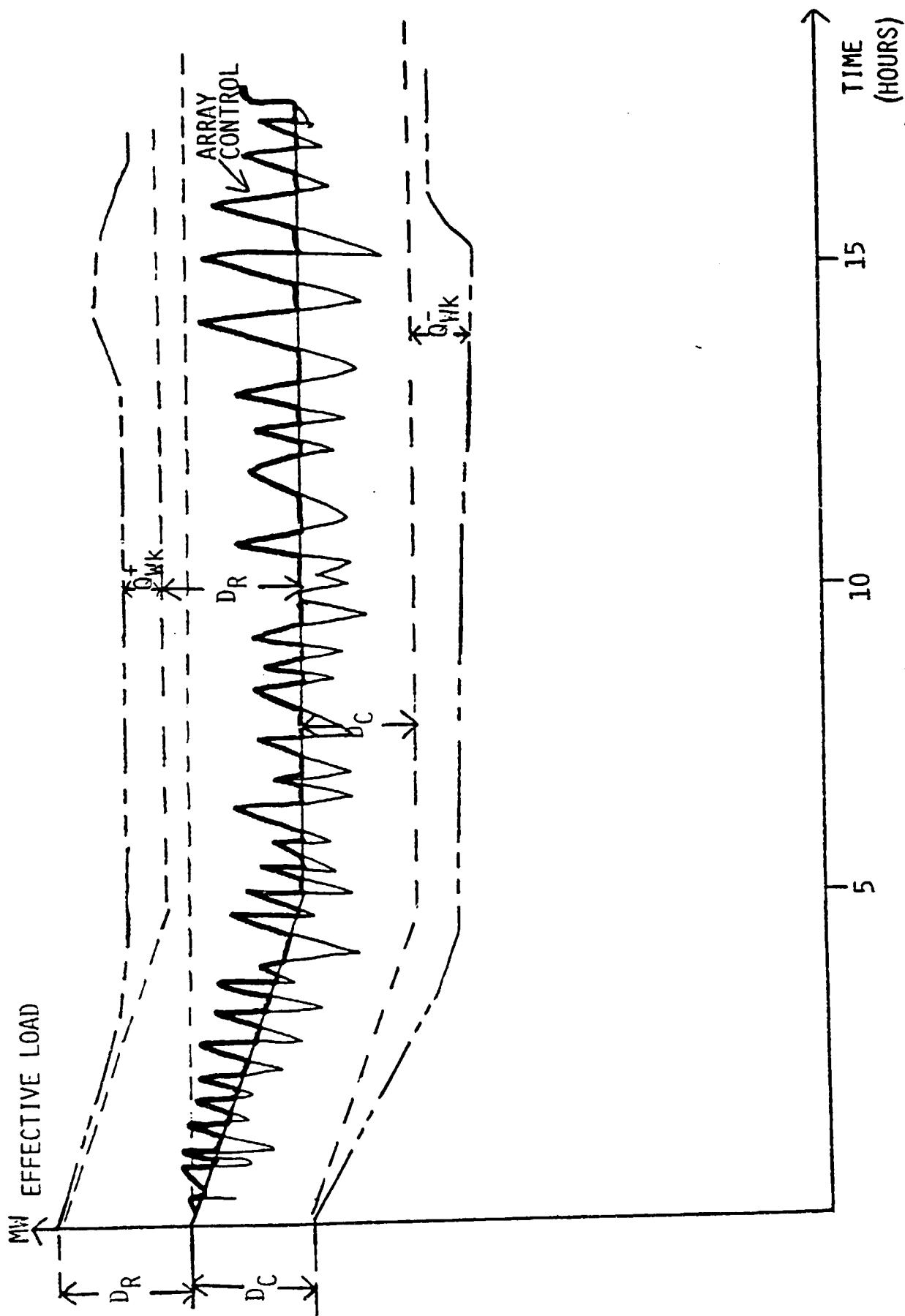
Figure 7a. Spinning reserve and unloadable generation requirements for trend and cyclic wind power variation and the use of blade pitch control to eliminate unloadable generation require-

40
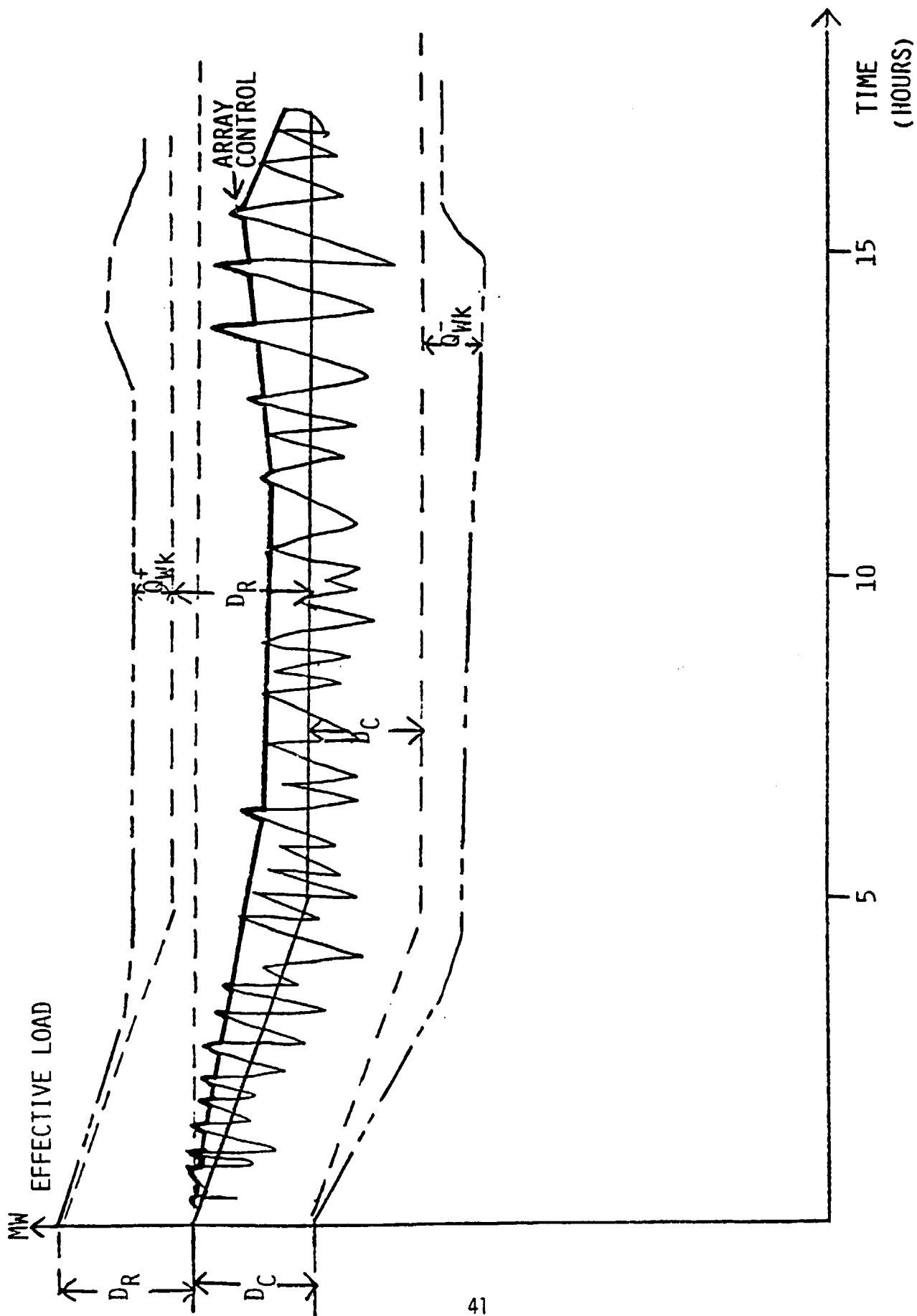
Figure 7b. Effect of coordinated blade pitch control in smoothing wind power variations below the predicted trend.

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considerably smaller for the storm front than for the front and the upper limit was higher for the storm front than for the front due to the large cyclic variation in storm cells that cannot be predicted by the trend wind power predictor.

The cyclic variation above $W(k + j/4)$ shown in Figure 8a and 8b due to cyclic variation in fronts and storm fronts respectively can be either clipped by coordinated blade pitch controls on the wind turbines or be compensated by the response of quick pickup units such as diesels, gas turbines, and hydro units. These quick pickup units would be committed by the quarter hour unit commitment in response to this cyclic variation, and thus could be used to compensate for it within a feedforward generation control.

The alternative of clipping of the wind power variation above $W(k + j/4)$ by wind turbines would lose "free" wind energy as shown in Figure 7a but would utilize controls on the units that produce the variation to eliminate it. The clipping of this cyclic variation above $W(k + j/4)$ would reduce or eliminate the need for unloadable generation reserve by reducing

or eliminating $Q_W^-(k + j/4 - 1)$ within the closed loop or feedback control structure.

There is no ability to clip wind power variations below the trend $W(t)$ unless the wind turbine arrays are scheduled to operate below the hour ahead predicted trend $W(t)$. This operation of the blade pitch control to clip

wind power variation to $W(k + j/4) - Q_W^+(k + j/4 - 1)$ as shown in Figure 7b does not eliminate spinning reserve or load following responsibility from the quarter-hourly updated unit commitment since the "free" wind power clipped below $W(t)$ must be provided by the economic, peaking, or regulating units and the startup of quick pickup or disconnection of interruptible load by the quarter hour updated unit commitment based on the component of spinning

reserve and load following requirement reflected in $Q_W^+(k + j/4 - 1)$.

It should be noted that the option to clip wind power by part or all of

$Q_W^+(k + j/4 - 1)$ below $W(t)$ or not at all is solely the function of generation control and has no effect on unit commitment. Since spinning

reserve is based on $W(k + j/4 - 1) - Q_W^+(k + j/4 - 1)$, the addition to spinning reserve due to wind is

$$P_W(t) - W(t) + Q_W^+(k + j/4 - 1)$$

The term $P_W(t)$ is the actual power produced from the array at time t. The generation control composed of automatic generation control of steam turbine units, feedforward control of quick pickup units, and feedback control can allow this addition to spinning reserve to reside on the wind turbines if no array control is utilized or to reside on steam turbine, quick pickup unit, and wind turbines if feedback control of the wind turbine array power is

FIGURE 8A. THE PREDICTED UPPER AND LOWER LIMITS FOR WIND POWER VARIATION COMPARED TO ACTUAL WIND POWER VARIATION FOR A STORM.

TIME IN MINUTES(1 TO 6 PM)

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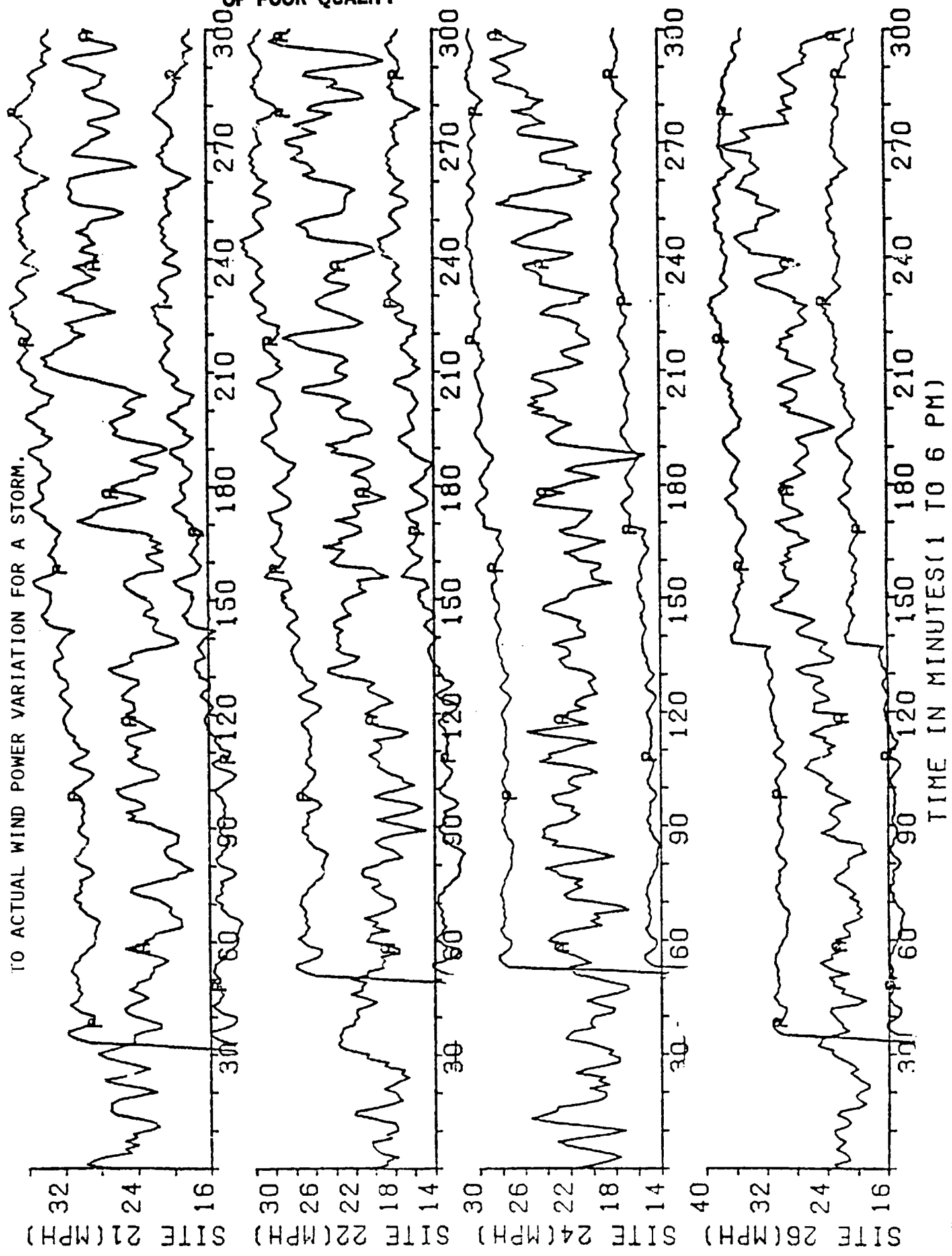
FIGURE 8B. PREDICTED UPPER AND LOWER LIMITS FOR WIND POWER VARIATION COMPARED TO ACTUAL WIND POWER VARIATION FOR A STORM FRONT.

TIME IN MINUTES (3 TO 10 PM)
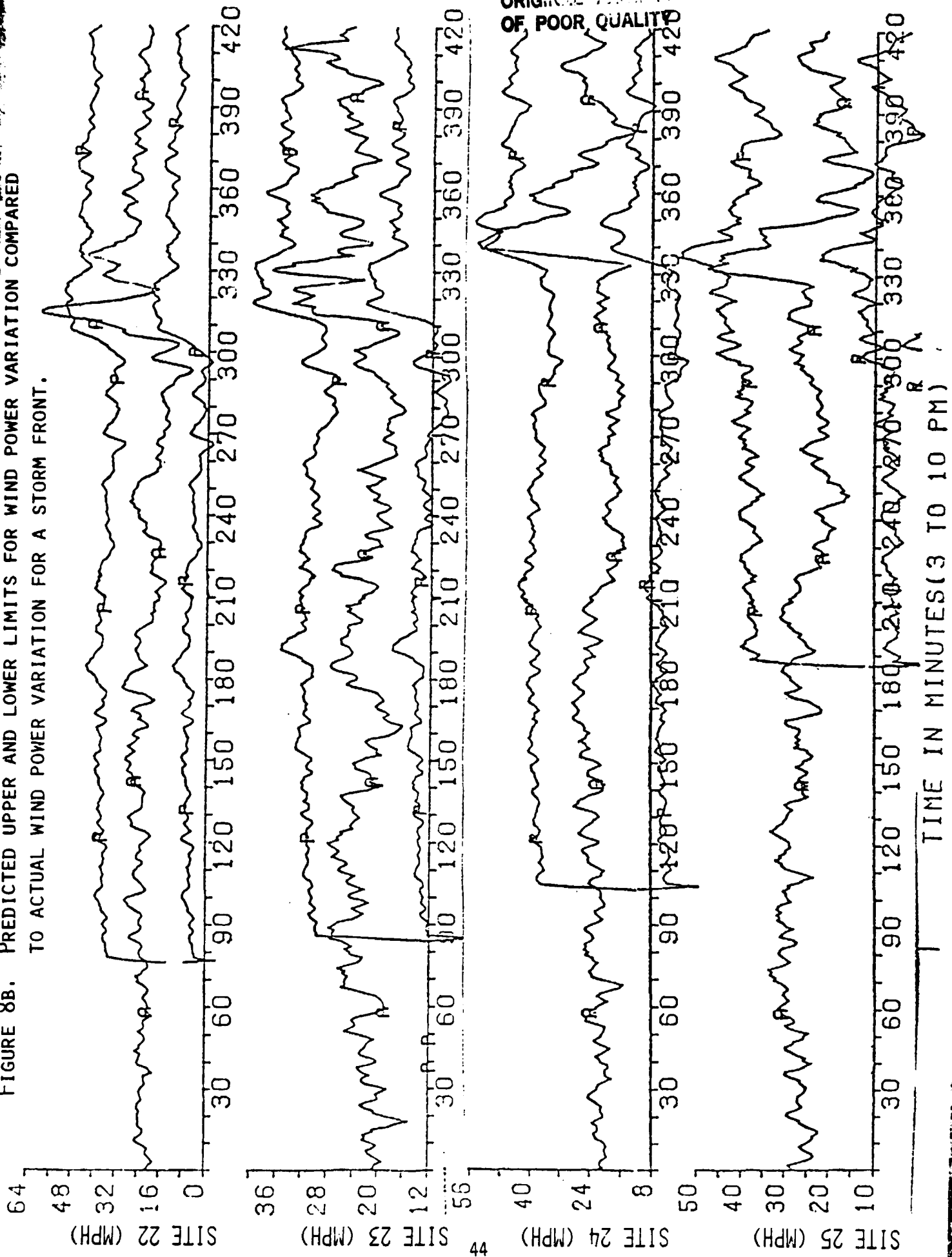
undertaken.

2.6 MODIFIED GENERATION CONTROL

The automatic generation control has generally performed the regulation function of attempting to maintain frequency close to a nominal value and matching generation to load change thus nulling area control error which is a measure of the mismatch in load and generation. The load following requirement on automatic generation control requires that the parameters of the AGC are set to command sufficient generation change in 10 minutes to null area control error. The automatic generation control load following capability is of no value unless the unit commitment has provided through constraint (6) the load following capability given by (3). The load following capability within the automatic generation control must also meet or exceed that given by (3). Results in [8] indicate that insufficient load following capability in either unit commitment or automatic generation control will cause large excessive area control errors that are sustained for periods much longer than 10 minutes which violates the NERC guidelines [19] that require (a) the area control error maxima and average values over ten minutes to be below a certain threshold based on system size and (b) that area control error must pass through zero in every ten minute period.

It is conceivable that automatic generation control response capability could be adjusted to each update of the quarter-hourly unit commitment to provide LF(k + j/4 - 1) given by (3) for the unit commitment. However, the use of conventional generation to meet these requirements for wind power variation due to significant wind speeds changes or passage of meteorological events would:

(1) increase fuel costs on the units committed to providing LF(k + j/4 - 1) in (6);

(2) increase maintenance costs, increase forced outage rates, and reduce unit lifetime due to the large continual cycling of these units.

An improved generation control strategy would utilize:

(1) normal automatic generation control that without wind variation is totally responsible under normal conditions to maintain system electrical frequency at 60 hz and regulate total system generation to track load variations;

(2) array controls that would smooth the effects of turbulence; slow trend; fast trend variations due to fronts, storms, and thunderstorms; and cyclic variations due to turbulence, fronts, storms, and thunderstorms from single and multiple arrays. The closed loop array controls would utilize a coordinated blade pitch control of all wind turbines in an array based on information about the capability of the utility's controls to handle these wind power variation components. Such closed loop array controls were discussed in [8]. These array controls utilized fast wind power variation prediction but make no effort to predict power variation from meteorological events since the

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application of the proposed control does not emphasize meteorological events;

(3) a feedforward generation control developed to control the fast responding regulation and peaking units committed by the quarter-hour unit commitment update and even faster responding quick pickup units that would be committed in the minute unit commitment update. At present, quick pickup units are not generally utilized in automatic generation control and generally not all peaking and regulation units are utilized. If peaking, regulating, and quick pickup units are under the automatic generation control, their response rate capabilities are generally not fully exploited. Thus, this feedforward generation control would control the units committed by quarter hour updated unit commitment. This feedforward control would utilize the response capabilities of these units to compensate for normal turbulence and the fast trend and cyclic wind variation for meteorological events.

The normal automatic generation control, closed loop array control, and feedforward generation control would be coordinated to provide the best control performance needed to maintain reliable operation and minimize the total cost of regulation of these wind power variation components.

The procedure developed in [8] for this modified generation control based on prediction of wind power variation at least 20 minutes ahead of real time. Although the procedure was evaluated for turbulence (normal) wind condition and not for meteorological event wind conditions, the procedure could be adapted to utilize the trend wind power and trend error wind power prediction as follows:

(1) determine the ramping capability $\Delta \dot{P}_G$ (MW/min, up and down) for the conventional generation on regulation. Then, the maximum ten minute change in generation is

$$\Delta P_G = 10 \, |\Delta \dot{P}_G|$$

(2) determine the maximum change in load in a ten minute period (ΔP_L max) based on the 24 hour ahead load prediction

(3) the maximum wind power change in 10 minutes must satisfy constraints

$$\Delta P_{Wmax} \leq \Delta P_G - \Delta P_{L_{max}}$$

based on the NERC operating reliability requirement that the area control error must be zero at least once in a 10 minute interval than the maximum change in wind that can be accommodated by AGC(ΔP_{Wmax}) must also satisfy [8]

$$\Delta P_{Wmax} \leq \Delta P_G - .675 \, \Delta P_{L_{max}} -22.5$$

based on NERC operating reliability requirement that the average area control error be less than some limit (Ld) that is proportional to the maximum change in load. The second constraint is more binding than the

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first. The level ΔP_{Wmax} of generation change out of steam turbine units that a utility is willing to utilize to compensate for wind power change must satisfy the above two constraints but is generally much smaller than the level determined by the constraint. The actual level of ΔP_{Wmax} is set so that (1) sufficient AGC response rate capability is provided to compensate for the maximum first contingency loss of generation, (2) excessive fuel is not consumed in ramping large steam turbines to compensate for wind generation change, (3) excessive maintenance and unit loss of life is not sustained on these large steam units for attempting to compensate for wind power variation. The level ΔP_{Wmax} set by the utility will be used to determine the feedforward and closed loop control in the next step of the generation control strategy.

(4) given a particular penetration of wind turbines, determine the control regime knowing present wind generation $P_W(k + j/4 - 1)$ predicted trend wind generation $W(k + j/4)$ predicted error $(Q_W^+(k + j/4 - 1)$ $Q_W^-(k + j/4 - 1))$ and the maximum increase $P_F^+(k + j/4 - 1)$ and decrease $P_F^-(k + j/4 - 1)$ in generation in 10 minutes for units under feedforward generation control.

(i) run open loop without feedforward or closed loop control if

$$\Delta P_{Wmax}(k+j/4-1) > \quad [W(k+j/4-P_W(k+j/4-1)]+Q^-(k+j/4-1)=P_u(k+j/4-1)$$
$$\text{if } W(k+j/4)-P_W(k+j/4-1) > 0$$

$$-\Delta P_{Wmax}(k+j/4-1) < \quad [W(k+j/4)-P_W(k+j/4-1)]-Q_W^+(k+j/4-1)=P_d(k+j/4-1)$$
$$\text{if } W(k+j/4)-P_W(k+j/4-1) < 0 \qquad (7)$$

This control requires the allocated change in wind generation for normal AGC to exceed the predicted trend change (up or down) plus the appropriate error

(ii) run with feedforward control if

$$\Delta P_{W_{max}}(k+j/4-1)+P_F^-(k+j/4-1) > P_u(k+j/4-1)$$
$$\text{if } W(k+j/4)-P_W(k+j/4-1) \geq 0$$

$$\Delta P_{W_{max}}(k+j/4-1)+P_F^+(k+j/4-1) > -P_d(k+j/4-1)$$
$$\text{if } W(k+j/4)-P_W(k+j/4-1) < 0$$
$$(8)$$

This feedforward control would not be utilized if (7) were satisfied. If (7) were violated, the response capability of the quick pickup units $P_F(k + j/4 - 1)$ would be added to that

provided for wind by $AGC\Delta P_{W_{max}}(k+j/4-1)$. The quick pickup units would be adjusted based on a maximum required change of

$$\Delta QP(k+j/4-1) = \quad P_u(k+j/4-1)-P_u(k+\tfrac{j-1}{4}-1)-P_{W_{max}}(k+j/4-1)+P_W(k+\tfrac{j-1}{4}-1)$$

$$\text{if } W(k+j/4)-P_W(k+j/4-1) \geq 0$$

$$P_d(k+j/4-1)-P_d(k+\tfrac{j-1}{4}-1)-P_{W_{max}}(k+j/4-1)+P_{W_{max}}(k+\tfrac{j-1}{4}-1)$$

$$\text{if } W(k+j/4)-P_W(k+j/4-1) < 0$$

where

$$[1-\beta(k+j/4-1)]QP(k+j/4-1) = [1-\beta(k+\tfrac{j-1}{4}-1)]QP(k+j/4-1)+ \Delta QP(k+\tfrac{j-1}{4}-1) \tag{9}$$

$$P_F^+(k+j/4-1) = \beta(k+j/4-1)QP(k+j/4-1)$$

$$P_F^-(k+j/4-1) = [1-\beta(k+j/4-1)]QP(k+j/4-1)$$

$P_F^-(k+j/4-1)$ is the portion of $QP(k+j/4-1)$ that is connected and thus can be unloaded in 15 minutes at $k+j/4-1$. $P_F^+(k+j/4-1)$ is the portion of quick pickup capacity that is either disconnected or connected and unloaded at $k+j/4-1$. It is assumed that quick pickup units can be connected and loaded to full capacity in 15 minutes or completely unloaded and disconnected in 15 minutes. The quarter hour updated unit commitment will attempt to reduce $P_F^-(k+j/4-1)$ and thus keep the response capability $P_F^+(k+j/4-1)$ to wind generation decreases large based on the spinning reserve constraints (1,4) on the unit commitment.

Reducing $P_F^-(k+j/4-1)$ by replacing quick pickup units by lower cost standby economic, peaking, and regulating units also reduces operating costs. The actual feedforward generation control would be based on the area control error in a manner similar to regulating units on AGC.

(iii) Run with feedforward and closed loop control if

$$\Delta P_{W_{max}}(k+j/4-1)+P_F^-(k+j/4-1) < P_u(k+j/4-1)$$

$$\text{if } W(k+j/4)-P_W(k+j/4-1) \geq 0$$

$$\Delta P_{W_{max}}(k+j/4-1)+P_F(k+j/4-1) < -P_d(k+j/4-1)$$

$$\text{if } W(k+j/4)-P_W(k+j/4-1) \leq 0 \tag{10}$$

The wind turbine array control can reduce the wind power increase to

$$P_W(k+j/4-1) = \Delta P_{W_{max}}(k+j/4-1) + P_F(k+j/4-1)$$

$$\leq P_u(k+j/4-1) \tag{11}$$

The wind turbine array control can attempt to limit the wind power decrease to

$$P_W(k+j/4-1) = -[\xi \Delta P_W(k+j/4-1) + P_F^+(k+j/4-1)]$$

$$\geq P_d(k+j/4-1) \tag{12}$$

where ξ can be either 0 or ξ_0 $(0 \leq \xi_0 \leq 1)$ depending on the level of the predicted power output. The power decrease can only be reduced if the hour prediction interval is used to start reducing wind power early in anticipation of the total change required in the next hour. In addition, if wind power error is large, the closed loop array may cause the array to operate at less than its uncontrolled open loop generation levels so that sudden shutdown or large reductions in wind generation from the array can be handled by the AGC and feedforward control.

This generation control strategy allows the utility to set the level of generation change $(\Delta P_{W_{max}})$ in 10 minutes out of the steam turbine units on automatic generation control and economic dispatch it is willing to devote to compensating for wind generation change $\Delta P_{W_{max}}(k+j/4-1)$ can be changed based on the level of wind generation change expected or based on an operating policy of the utility operators toward compensating for wind power changes. If the maximum increase in wind generation $P_u(k+j/4-1)$ or maximum predicted wind generation decrease $P_d(k+j/4-1)$ in 10 minutes can be handled using the automatic generation control capability $\Delta P_{W_{max}}(k+j/4-1)$ devoted to tracking wind generation, no change in feedforward or closed loop array control is needed. However, if the maximum predicted change in wind exceeds $\Delta P_{W_{max}}(k+j/4-1)$, feedforward control of quick pickup units is required up to a maximum decrease $(P_F^-(k+j/4-1))$ or increase $P_F^+(k+j/4-1)$ that is to be utilized to compensate for wind generation change. $P_F^+(k+j/4-1)$ is the generation capacity of quick pickup units that are not disconnected or connected and unloaded that is counted in spinning reserve and can be connected and loaded in 15 minutes. $P_F^-(k+j/4-1)$ is the quick pickup generation connected that can be unloaded in 15 minutes and counted in unloadable generation reserve. $\Delta QP(k+j/4-1)$ is the change in the generation capacity of quick pickup units connected and depends on the change in wind generation minus the change in response of steam units under automatic generation control that is affected by connection of standby peaking, economic, and regulating units.

If the maximum wind generation increase $P_u(k+j/4-1)$ and decrease $P_d(k+j/4-1)$ is greater than the combined allocated response of steam unit under AGC and quick pickup units under feedforward control, then closed loop array control is utilized to reduce worst case wind generation increase to

generation increase $P_u(k+j/4-1)$ includes the predicted trend increase over ten minutes plus the error $Q_W^-(k+j/4-1)$.

Wind generation decrease must be compensated by nonwind generation increase. The additional spinning reserve for wind generation prediction error $Q_W^+(k+j/4-1)$ is carried by steam turbine units under automatic generation control and by quick pickup units under feedforward control. Since maximum possible wind generation decrease in ten minutes $P_d(k+j/4-1)$ is based on the total error $Q_W^+(k+j/4-1)$ and the predicted hour ahead trend change

$$W_{k+j/4} - R_W(k+j/4-1)$$

the wind generation control reduces wind generation earlier than actually required and more than actually required to produce a backoff reserve. The level of this backoff reserve is based on the value of ξ_0 selected. This backoff reserve means the wind turbine array produces less power than it actually can given the wind at any particular time and thus when the wind speed actually drops the wind power drop out of the array is substantially less.

It is clear that the proposed unit commitment procedure requires the development of the one or more hour trend wind predictor and the error wind power predictor to compensate for the inherent delays in starting up regulation and peaking, quick pickup units, and wind turbines, respectively. The proposed control procedure requires prediction to (1) permit the units under automatic generation control and the peaking, regulating, and quick pickup units under feedforward generation control to anticipate the large trend and cyclic wind power variations predicted and thus effectively increase their ability to respond; (2) the closed loop array control to anticipate and thus reduce total wind power change and rate of change by (a) beginning the wind generation increase or decrease before it actually occurs and (b) by clipping cyclic wind power variation making the wind generation change easier to cope with by AGC or feedforward generation control; and (3) to properly coordinate the system AGC, feedforward generation control, and closed loop array control portion of the control task. It should be noted that if the array control is capable of anticipating a wind generation increase or clipping cyclic wind power variations below the trend wind power variation $W(k+j/4-1)$ requires the array to operate below the level possible with the wind speeds observed at all wind turbines in the array. If the closed loop array controls operate the array below the predicted trend $W(k+j/4-1)$, the closed loop array control can compensate for positive or small negative errors in predicting $W(k+j/4-1)$ since small negative errors and all positive errors in predicting wind array power are eliminated. This type of control of wind array power will be necessary when errors in predicting wind power trend $W(t)$ are large and can change rapidly such as during storms and thunderstorms.

If either the hour trend and trend error wind power predictor were not feasible, the solution to the unit commitment and control problems proposed in [17] would be implemented with the following consequences:

(1) the maximum wind penetration would be limited by the farm penetration constraint to the maximum first contingency loss of conventional generation [17]. If the spinning reserve and load following capability were increased with array capacity, significant fuel, operating, and maintenance costs, that would be added would significantly hurt the economics of wind generation, would be added;

(2) addition to spinning reserve and load following requirements on unit commitment would be required in proportion to the maximum cyclic power variations anticipated for the next 24 hour period. These maximum cyclic deviations would be for the cyclic wind variation during the worst front, storm, or thunderstorm that can be anticipated for that day whether it occurs or not. These additional spinning and load following reserves would be included in these requirements (3) for the entire day or a significant portion of it since the time of arrival of meteorological events could not be predicted accurately 24 hours ahead. This addition to spinning reserve, unloadable generation, and load following could be significant and again reduce the economic viability of wind generation;

(3) a response and response rate capability would be provided in excess of that required of the automatic generation control and closed loop array control. These control actions increase operating costs since this constant adjustment of generation levels increases fuel costs and operating and maintenance costs, and since the use of array control to smooth total wind power variation reduces the energy output of the array. These costs are in addition to the above costs that exist purely for connecting the additional generation since these regulations costs are attributed to continually changing generation levels and costs for the lost energy from arrays required to clip or smooth cyclic and trend wind power variations;

(4) the reduced control performance by lack of feedforward generation control units and the lack of anticipation and coordination in the system automatic generation control, closed loop array control, and feedforward generation control;

(5) the operating reserve would not be adjusted for arrival of meteorological events but will be set 24 hours ahead based on the worst anticipated drops in wind generation over the next 24 hour period.

The recent HECO decision to install an 8% penetration wind array that exceeds typical spinning reserve and load following capability points out the need for this new solution [3] to the unit commitment and control problems because possibly severe reliability or economic penalties can be anticipated if the entire array is built and exceeds the farm penetration constraint. It is anticipated that other utilities will eventually desire to install higher penetrations (% wind capacity) than typical spinning reserve levels (5%) as wind technology improves resulting in larger and more efficient wind turbines and thus larger wind generation penetrations. Although there are more significant penalties for lack of a modified unit commitment when penetration levels exceed the farm penetration constraint, the above economic penalties are very significant for wind arrays of any size and thus further development of this modified unit commitment and generation control is necessary to

minimize the economic penalties.

SECTION 3

WIND POWER PREDICTION METHODS

Wind power prediction of diurnal trend, turbulence, and meteorological event trend wind power variation is required for the modified unit commitment and for the modified generation control strategy. The methods required for predicting each of these wind power components is different and obviously their use in the 24 hour, and quarter updated unit commitment, and in the automatic generation control, feedforward generation control, and closed loop array control are different. The prediction of the weather map (meteorological event) trend wind power change is by far the most important because

(1) the weather map fluctuations associated with energy spectrum below 5 cycles/hour are generally correlated between sites in an array and have relatively larger energy than "gusts". The high correlations in weather map fluctuations make the power variations on each wind turbine appear quite similar and thus cause large power variations out of the array;

(2) the turbulence or "gusts" wind speed variation component associated with the spectrum above 5 cycles/hour has less energy than the "weather map fluctuation" component and is generally uncorrelated between sites. The lack of correlation of turbulence between sites generally will cause cancellation of wind variation between the different wind turbine sites which greatly reduce the turbulence induced power variations out of an array.

It is impossible to discuss whether there are or are not any meteorological events in the spectrum of Figure 1. This information is lost in the calculation of the energy spectrum. However, the conclusion that the wind speed variation associated with the energy spectrum below 5 hz is of concern in operation and control of utilities is valid whether there are meteorological events in this spectrum or not. The validity of the concern is based on the energy of these variations and the high correlation between wind turbines in an array for such variation. It will be our custom to refer to weather map fluctuations as meteorological events in our discussion.

Section 3.1 first reviews previous literature on prediction of diurnal, meteorological event, and turbulence induced wind power variation. The least squares models used for prediction of meteorological events in this research is then presented in Section 3.2. The methodology for properly filtering, determining the direction of the meteorological event, and determining propagation delay for the event is also presented.

3.1 REVIEW OF WIND POWER PREDICTION METHODS

The previous literature on prediction of diurnal trend wind power variation and the estimation of turbulence induced wind power variation for use in the 24 hour, and quarter hour updated unit commitment is now reviewed.

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The turbulence prediction method developed in [2] would attempt to estimate the peak W_O turbulence induced wind power variation defined by

$$P\{W(t) \leq W_O\} = .99$$

based on a Kaimal spectrum of wind speed, a model of correlation of wind speed between wind turbine sites, and a transformation of wind speed to wind power variation for the wind turbine models in the particular array. The estimation of the peak wind power W_O would also depend on the average wind speed measured at the wind turbines in the cluster and on the stability of the meteorological conditions at the cluster. The estimation procedure would eliminate the need to estimate both the actual wind power and the variation around this estimate. Moreover, the Kaimal spectrum used in [2] is considered to be more accurate than the Davenport spectrum used in [8]. Finally, since the estimation can be updated every quarter hour (or minute if necessary), since the error is included in the estimate, and since the actual magnitude of turbulence induced variation out of arrays [3] even for meteorological events is small, there is no need for prediction of turbulence induced wind power variation. Thus, the effects of turbulence for normal or meteorological event wind conditions can be estimated and then updated as meteorological conditions change. The method [2] is utilized and extended for estimating the error in predicting trend wind power variation in Section 2 of this report. This error prediction would include turbulence but would also include error in predicting trend wind power variation and the large cyclic wind variation associated with storms and thunderstorms.

A methodology for subhour wind forecasts was developed in [7]. The approach was developed to provide forecasts of trend 10 minutes ahead for the modified generation control as well as one to six hours ahead for the modified unit commitment strategies. The OEM method, a regression method, and a persistence method were selected for evaluation in [5] based on the following criteria for a good predictor:

*   techniques should be easily automatable

*   ideally techniques should have some physically meaningful basis

*   any predictors used must be available in real time

*   techniques should be applicable to a variety of forecast output formats to meet users needs

*   techniques should be applicable for prediction in time frames ranging from 10 minutes to a few hours

*   techniques should permit update to be made easily upon demand

The mean, standard deviation about the mean, the trend, and the standard deviation of the trend component were predicted at successive 10 minute time steps from 10-60 minutes ahead using a persistence, an autoregressive, and an OEM model. The same four variables were also predicted using the persistence, autoregressive, and OEM models for successive hour time steps from 1-6 hours and for successive half hour time steps from 1/2 to 3 hours. The results are

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quite preliminary since the research is at an early stage. The persistence model and OEM were clearly superior to the autoregressive model for predicting all four variables and for all prediction intervals. Persistence performs nearly as well as OEM for shorter (fewer iterations) prediction intervals using each basic time step (either 10 minutes, 30 minutes, or 1 hour). Trend forecasts were generally poor using all three methods and improvements could be made if there was a method of discriminating whether there would be speed change for a site. The large number of cases in the dependent set, where no significant wind speed change occurs and the smaller number of cases where change occurs in the set of dependent cases, makes the techniques studied relatively less effective in predicting large wind speed changes. The research performed in this study suggest:

(1) knowledge of apriori meteorological information about the arrival of meteorological events;

(2) measurements of wind speed and direction at wind measurement sites that encircle the wind turbine cluster and that experience the meteorological event;

(3) measurement of pressure and temperature and their changes at the wind measurement sites that encircle the turbine array;

(4) determination of the speed of the meteorological events from wind speed, wind speed direction, pressure and temperature measurements, and their gradients over time and space;

would provide the information required to accurately predict meteorological event induced wind power changes.

A method for forecasting trend wind power variation hourly over a 24 hour interval is proposed in [6]. This type of prediction would be useful in setting operating reserve, spinning reserve, unloadable generation and load following reserve in the 24 hour unit commitment. The model first develops a static probabilistic transformation that relates hourly average wind power to hourly averaged wind speed at a particular wind turbine site for a particular wind turbine model (MOD-2, MOD-1, etc.). This static probabilistic transformation of a wind turbine was then used in conjunction with semiobjective and model output statistics wind forecasts. The perfomance of the wind power forecasts was based on properly forecasting whether average wind power output for a MOD-2 lies above or below 600, 1200, 1800, or 2400 kilowatts. The reliability and skill level for these two wind power forecasts was encouraging.

3.2 A WIND SPEED PREDICTION METHODOLOGY FOR METEOROLOGICAL EVENTS

An effort was made in [3] to establish the feasibility or predicting wind speeds at 26 sites in SESAME array of 27 wind measurement sites in a 80 by 80 mile area in Oklahoma. The wind speed measurements were taken at a height of 13 feet and at a sampling rate of one per minute. A correlated echelon model was used

$$W_i(t) = m_i + A_{ij}(T)[W_j(t - T) - m_j]$$

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where

$$A_{ij} = \frac{P_{ij}(T)\sigma_i}{\sigma_j} \qquad (13)$$

m_i, m_j means of wind speed at sites i and j over time interval $(0, N\Delta)$

σ_i, σ_j standard deviations of wind speed at sites i and j over the time interval $(0, N)$

$T_{ij} = k_{ij}\Delta$ delay between the arrival of meteorological event at site i and j prediction interval

$P_{ij}(T_{ij})$ correlation coefficient of wind speed at site i and the wind speed at site j delayed by T_{ij}

Δ 1 minute sampling period for the wind data

The correlation echelon model assumes the wind speeds at the two sites i and j are both stationary processes that can have different mean and variance due to surface roughness and site specific effects. The characteristics of the meteorological event captured in the wind speed records is assumed to propagate from site i to j with the speed and direction of the motion of the meteorological event itself.

The methodology used to determine the model (3) is

(1)   filter each wind record over time interval $[0, N]$ using a moving average filter

(2)   calculate m_i, m_j, σ_i, and σ_j of the filtered reference wind measurement record $W_j(t)$ and the wind measurement record $W_i(t)$ where prediction is desired

(3)   calculate the correlation

$$P_{ij}(\tau) = \frac{C_{ij}(\tau)}{\sigma_i \sigma_j}$$

$$C_{ij}(\tau) = \sum_{k=1}^{N} \frac{X_i(k\Delta)X_j(k\Delta - \tau)}{N} \ ; \ X_i(k) = W_i(k) - m_i$$

(4)   find the value of T_{ij} and $P_{ij}(T_{ij})$ that maximizes $P_{ij}(\tau)$

(5)   predict $W_i(t)$ using

$$W_i(t + T_{ij}) = m_i - \frac{P_{ij}(T_{ij})\sigma_i}{\sigma_j} [W_j(t) - m_j]$$

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given record of $W_i(t)$. Determine the mean square error for the predictor based on error $W_i(t) - \hat{W}_i(t)$.

The results obtained from the SESAME data for ten minute moving average filtered data showed that accurate estimates were possible at small geographical distances from the reference site. The prediction intervals T_{ij} were also very small. The estimation errors were much larger at longer geographical distances. Although there was good quality estimation at small geographical distances, the prediction intervals were so small that it was questionable whether prediction was actually being accomplished.

The results obtained for filtering data with an hour moving average filter were encouraging because reasonable quality estimation was observed for sites reasonably distant from the reference site. The delays T_{ij} for some of the sites with reasonable quality estimation was 15 minutes and thus the possibility that prediction could be performed was indicated.

A correlation echelon model that would utilize wind speed measurements at several reference sites has the form

$$\hat{W}_i(t) = m_i + \frac{1}{M_i} \sum_{j=1}^{M_i} P_{ij}(T_{ij}) \frac{\sigma_i}{\sigma_j}[W_j(t - T_{ij}) - m_j] \tag{14}$$

where

M_i number of sites where measurements are taken

$W_i(t)$ wind speed estimate at site i

m_i, m_j mean wind speed at site i and sites j = 1,2,...,M_i

σ_i, σ_j standard deviation of the wind speed at site i and sites j = 1,2,...,M_i

$P_{ij}(\tau)$ normalized cross correlation of wind speed at site i and site j

T_{ij} delay between the time meteorological event first effects sites j and the time it first effects site i. This delay T_{ij} is chosen as the value τ where normalized cross correlation $P_{ij}(\tau)$ is maximum

$W_j(t-T_{ij})$ delayed wind speed measurement record at site j

A similar recursive least squares model is proposed that has the form

$$\hat{W}_i(N\Delta) = \sum_{j=1}^{M_i} a_{ij}(N)W_j([N - k_{ij}]\Delta) + b_i(N) \tag{15}$$

where $\{a_{ij}\} \sum_{j=1}^{M_i}$ and b_i are chosen to minimize $J(a_{i1}, a_{i2}, \ldots, a_{iMi}, b_i) =$

$$\sum_{n=1}^{N} [W_i(n\Delta) - \sum_{j=1}^{M_i} a_{ij}(n)W_j([n - k_{ij}]\Delta) - b_i(n)]^2$$

where $t = N\Delta$ and $T_{ij} = k_{ij}\Delta$. If the processes ar stationary then

$$a_{ij}(N) = \frac{1}{M_i} P_{ij}(T_{ij})\frac{\sigma_i}{\sigma_j} = a_{ij}$$

$$b_i(N) = m_i - \sum_{j=1}^{M_i} a_{ij}m_j = b_i$$

A recursive least squares algorithm requires apriori knowledge of $T_{ij} = k_{ij}\Delta$
but allows $\{a_{ij}(N)\}_{j=1}^{M_i}$ and $b_i(N)$ to be updated at every sampling period $t_N = N\Delta$. The method for selecting $T_{ij} = k_{ij}\Delta$ is critical to the performance of the predictor and is discussed in the next section.

Three different predictive models were tested. The individual site predictive model (15) predicts wind speed at each site i in the wind turbine cluster using several individual wind speed measurements j each with its own delay T_{ij}. The group/site predictive model predicts wind speeds at each prediction site i in the wind turbine cluster based on (a) an average record of wind speed in a group of N_j reference sites

$$W_r(t) = \frac{1}{N_j} \sum_{j\epsilon J_o} W_j(t)$$

and (b) the average delay between the prediction site i and the group of reference sites

$$T_i = \frac{1}{N_j} \sum_{j\epsilon J_o} T_{ij}$$

The group/site prediction model has the form

$$W_i(t) = a_{ir}W_r(t - T_i) + b_{ir}$$

The accuracy of this model was shown to be inferior to the individual site model but using average wind speed records with average delays from several reference groups was found to greatly improve prediction accuracy over that for one reference group. The group/group predictive model averages wind speed records at all prediction sites in a wind turbine cluster and all reference sites in a reference group and predicts the averaged wind speed record in the wind turbine cluster using a delay averaged over all prediction sites in the wind turbine cluster and all sites in the reference group. The averaged reference wind record for the N_j reference records is

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$$W_r(t) = \frac{1}{N_j} \sum_{j \epsilon J_o} W_j(t)$$

An averaged wind speed record for the N_k sites in prediction group k is

$$W_k(t) = \frac{1}{N_k} \sum_{i \epsilon I_k} W_i(t)$$

and an average group delay between reference site $j \epsilon J_o$ and prediction sites $i \epsilon I_k$

$$T(k) = \frac{1}{N_j N_k} \sum_{j \epsilon J_o} \sum_{i \epsilon I_k} T_{ij}$$

The single averaged reference group signal $W_r(t)$ is delayed by T(k) to produce a recursive least squares predictor of the averaged wind speed record for group k. The group/group predictor has the form

$$W_k(t) = a_{kr} W_r(t - T(k)) + b_{kr}$$

The implementation of any of the above models requires

(1) properly filtering the wind speed records at all sites based on the propagation speed of the meteorological event being predicted;

(2) properly determining the direction of propagation of the meteorological event which may or may not be identical with wind speed direction at individual wind measurement sites;

(3) properly determining the delay between the reference wind measurement sites and those where prediction is being attempted;

It is clear that although accurate prediction has been accomplished in all cases studied, the procedure would be much more accurate and be able to be implemented more successfully on-line if

(1) meteorological forecasts of the time of arrival and departure as well as the speed and direction of motion of the metoeorological event were available;

(2) measurement of pressure and temperature, and their gradients were available.

The need to (a) very carefully filter the records, (b) utilize several reference wind speed measurements, (c) utilize several wind speed measurements in the geoegraphical region of the wind turbine cluster where prediction is desired, and (d) compute correlation ($P_{ij}(T_{ij})$) and delay (T_{ij}) between all pairs of wind measurement sites indicated that wind speed and direction measurements are very much corrupted by turbulence and site specific variations that mask the meteorological event information. Thus, the need for additional measurements and forecasts is apparent.

Filtering of the measurement records at reference and prediction sites using a 2 minute moving average filter to eliminate turbulence can assist in accurately determining the direction and speed of propagation of the meteorological event. Filtering the records over longer intervals can cause serious distortion in the maximum, minimum, and average of the predicted wind speed and cause significant delay in the record. Long filter intervals were used in an attempt to predict wind power variations for storm fronts in our previous research [20]. Results in Section 4 indicate the filtering eliminated the very large cyclic variations and was not needed to determine propagation delay or propagation direction for the meteorological events as was considered necessary in this previous research.

The direction of propagation of the meteorological event was not always identical to the wind speed direction at individual sites or clusters of wind measurement sites. A procedure for determining the direction of propagation of the meteorological event was determined by calculating the peak correlation $P_{ij}(T_{ij})$ for all pairs of wind measurement sites

$$P_{ij}(T_{ij}) = \frac{1}{N} \sum_{n=1}^{N} \frac{[W_i(n\Delta)-m_i][W_j(([n-k_{ij}]\Delta)-m_j]}{\sigma_i \ \sigma_j}$$

$$m_i = \frac{1}{N} \sum_{n=1}^{N} W_i(n\Delta)$$

$$\sigma_i = \frac{1}{N-1} \sum_{n=1}^{N} (W_i(n\Delta) - m_i)^2$$

If sites $i_0 j_0 \epsilon I_\alpha$ are the sites of the system ordered in increasing distance in a particular direction α and $P_{i_0 j_0}(T_{i_0 j_0}) > P_{j_0 i_0}(T_{j_0 i_0})$ for all $i_0 > j_0$ indicate site j_0 is advanced by $T_{i_0 j_0}$ from the record i_0. Thus, $P_{i_0 j_0}(T_{i_0 j_0})$ being larger than $P_{j_0 i_0}(T_{j_0 i_0})$ implies that the phenomena hits j_0 first and then i_0 and not vice versa since delaying j_0, where the event effects first, achieves the larger correlation. If reference sites contain storm or thunderstorm cyclic variations, they cannot be used to determine the storm fronts propagation direction or delay since the individual storm cells do not propagate at the speed or direction of the storm front. The wind speed direction at a measurement site can be effected by site specific effects and not reflect front propagation direction. The observation of wind direction at several sites and the above procedure can accurately assess front propagation direction.

Selecting the proper delay $T_{i_0 j_0}$ between reference site j_0 and prediction site i_0 is difficult and cannot be based on a single pair of sites. The smoothing interval must be properly chosen or the delays between reference sites and prediction sites may be meaningless since the delays for different reference sites j_0 geographically close may give very different values of delay $T_{i_0 j_0}$ to the site i_0 where prediction is desired. The procedure to determine the delay is to

(1) find set of several reference sites $j\epsilon J_r$ in a small geographical region with a very high correlation $P_{j1j2}(T_{j1j2}) > .90$.

(2) find a set of several wind speed measurement sites I in a small geographical region (where the wind turbine cluster is located) that have high correlations $P_{i1i2}(T_{i1i2}) > .90$.

(3) if T_{ij} are fairly consistent for all $i\epsilon I$ $j\epsilon J$ and $P_{ij}(T_{ij}) > .60$ for all pairs $i\epsilon I$ and $j\epsilon J$, utilize the set of reference $j\epsilon J$ with delays T_{ij} to predict each site $i\epsilon I$.

This procedure may not determine the delays of the reference sites containing storm induced variation. If one had accurate forecasts of the speed of propagation or possibly other information on pressure and temperature gradients, one might be able to obtain the storm front propagation delay and thus eliminate the need for the procedure altogether.

The reference sites should be at a radius of 100 miles from the set of wind turbine clusters to permit hour ahead wind power prediction. The propagation speed and direction of the front is often different than the wind speed and direction at a wind measurement site. The propagation speed of the front can be either much larger or smaller than the wind speed. Since front propagation speed can be as high as 100 miles/hour, the reference sites must be at least 100 miles from the wind turbine clusters to insure hour ahead wind power prediction. If the frontal propagation speed is less than 100 mph, then the prediction interval will be longer. If an hour ahead prediction is desired for the unit commitment and generation control strategies discussed in Section 2, the wind power prediction would be provided before it is needed if the propagation delay was greater than one hour.

The reference sites to be used to predict the wind speed at the wind turbines in the array should not contain storm or thunderstorm cyclic variations since these cyclic variations are not correlated from site to site and thus cannot be predicted in the wind turbine clusters from the reference measurements. The use of reference sites without storm activity allows prediction of the propagation of the front containing the storm cells. The cyclic variation in the storm is then predicted or forecasted by predicting the error around the wind prediction itself using a procedure discussed in Section 7 of this report.

A procedure for changing the reference measurement sites and associated delays for a wind shift is proposed. The reference sites for a wind turbine cluster in a large wind turbine array is changed when the wind shift begins to affect the sites in that cluster. This procedure requires that the wind speed measurements record at reference sites in the direction of the incoming front be saved and used to determine delay and the predictor's parameters when the reference sites and delays are switched to those for the incoming front.

SECTION 4

A MODIFIED WIND SPEED PREDICTION METHOD

4.1 INTRODUCTION

The wind speed prediction methodology given in the previous section has several modifications from that given in our previous work [20]. These modifications are based on the work presented in this section. These modifications are:

(1) a moving average filter with long (10 minute - 2 hour) smoothing intervals may at time be necessary to increase the correlation and thus determine the meteorological event propagation direction. A moving average filter with a short 2 minute smoothing interval must be used for determining reference groups and prediction groups of wind measurement sites, and prediction delays T_{ij}.

(2) the smoothing interval used for the measurement records for producing a predicted wind speed record should never exceed 2 minutes or otherwise the average, maximum, minimum, and shape of the cyclic variations in that predicted wind record become greatly distorted;

(3) use of reference group measurement records that contain storms should be avoided since the wind speed prediction errors are much more than if reference without storm induced variation are used.

The error in predicting the propagation of a storm will be large since the shape of the cyclic wind speed variation change over time as the storm propagates. Since storms are local and since there may be several local storms, the prediction methodology will attempt to relate the storm in the reference group and any prediction site whether the reference group storm has propagated to the prediction site or not. Use of a reference group that does not contain the storm will thus more accurately predict the wind speed at all prediction sites whether they contain the same storm, a different storm, or no storm.

The meteorological event containing the wind shift and a set of storms is analyzed in Section 4.2 using a set of maps containing the wind speed and direction at the 27 sites in the SESAME array at a particular time. These maps are plotted at 20 minute intervals until the storms appear and at 10 minute intervals thereafter. An analysis of the effects of filtering on the accuracy of the wind prediction record is given in Section 4.3. An analysis of the effects of filtering on the estimation of the prediction delays as well as an analysis of the selection of reference sites on the accuracy of the wind prediction is given in Section 4.4.

4.2 PROPAGATION OF A STORM FRONT

The methodology for predicting wind speeds developed in the previous section is now tested in data from the SESAME array. This array of 27 meteorological measurement sites are located in an 80 x 80 mile square area near Tulsa, Oklahoma. The data utilized in this study was collected over a 3 month period in the spring of 1979. The wind speed in longitudinal and latitudinal directions, the nondirectional wind speed, pressure, temperature, and rainfall were all measured at these sites. The latitudinal and longitudinal wind speeds were used to determine wind velocity, magnitude, and direction of every site in the array. The nondirectional wind speed measurements were also retained, but the other meteorological data was unfortunately discarded at an earlier stage of the research [3]. This pressure and temperature information could have been quite useful in determining and confirming the speed and direction of motion of the meteorological event as indicated in Section 3.

The propagation of a storm front containing the propagation of the wind characterized by a sudden short duration drop in wind speed and a set of large cyclic wind speed variations in a set of local storm cells is now analyzed. The storm front occurs over a period from 3:00 - 10:00 p.m. on May 2, 1979. The wind measurement sites do not experience the wind direction change until 6:40 p.m. as observed on the map of wind speed and direction change plotted in Figure 9 for intervals of 20 minutes up until 7:00 p.m. and then at intervals of 10 minutes to 10:10 p.m. The wind shift propagates in a southeasterly direction based on both the direction of the wind and the propagation of the wind shift line on Figure 9j to 9t. The wind shift has affected all the sites by 8:40 and propagates at a speed of 40 mph.

The wind shift is accompanied by a set of recurrent storms that propagate in a southeasterly direction and then appear to split into two parts. One storm remains near sites 8, 16, and 28 and the other propagates in a southwesterly direction. This second storm propagates through the entire array in approximately three hours. These two storms disappear after 9:30 p.m. A second set of storms appears near site 2 at 8:50 p.m. and propagates in a southwesterly direction in a path similar to the portion of the first storm that continued to propagate through the entire array. Sites on the western side of the array are totally unaffected by the storm propagation. If reference sites used in prediction and prediction sites, where wind speed prediction is desired, both contain the large cyclic wind speed variations of a storm, the propagation of the storm will be predicted in the results to be presented. If either the reference or prediction sites do not contain storms in their wind measurement records, the propagation of the wind shift is predicted.

The storm is evidenced by a distortion of the wind speed direction from the direction of propagation of the front or wind shift. The distortion can appear as a large circular flow of wind around an eye, where wind speed is very small. The eye and associated circular flow will then propagate in a direction that appears to be related to but not identical to the direction of wind shift propagation. The distortion in wind direction can also be seen as a circular flow around both sides of an eye, where wind speed is small.

WIND MAP 1540 05/02/79

10 miles

10 miles

ORIG
OF POOR QUALITY

Figure 9a. Wind speed and direction maps for a front for the SESAME array
for 20 minute periods from 3:40 - 10:10 p.m.

WIND MAP   1600 05/02/79

Figure 9b.   Wind speed and direction maps for a front for the SESAME array
for 20 minute periods from 3:40 - 10:10 p.m.

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WIND MAP 1620 05/02/79

ORIGINAL PAGE IS
OF POOR QUALITY

Figure 9c. Wind speed and direction maps for a front for the SESAME array
for 20 minute periods from 3:40 - 10:10 p.m.

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WIND MAP AT 1640 PM

Figure 9d.   Wind speed and direction maps for a front for the SESAME array
             for 20 minute periods from 3:40 - 10:10 p.m.

WIND MAP   1700 05/02/79

Figure 9e.   Wind speed and direction maps for a front for the SESAME array
for 20 minute periods from 3:40 - 10:10 p.m.

WIND MAP 1720 05/02/79

Figure 9f.   Wind speed and direction maps for a front for the SESAME array
for 20 minute periods from 3:40 - 10:10 p.m.

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WIND MAP   1740 05/02/79

Figure 9g.   Wind speed and direction maps for a front for the SESAME array
for 20 minute periods from 3:40 – 10:10 p.m.

70

WIND MAP · 1800 05/02/79

Figure 9h. Wind speed and direction maps for a front for the SESAME array
for 20 minute periods from 3:40 - 10:10 p.m.

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WIND MAP   1820 05/02/79

Figure 9i.   Wind speed and direction maps for a front for the SESAME array
for 20 minute periods from 3:40 - 10:10 p.m.

72

WIND MAP   1840 05/02/79

WIND MAP AT 1840 PM
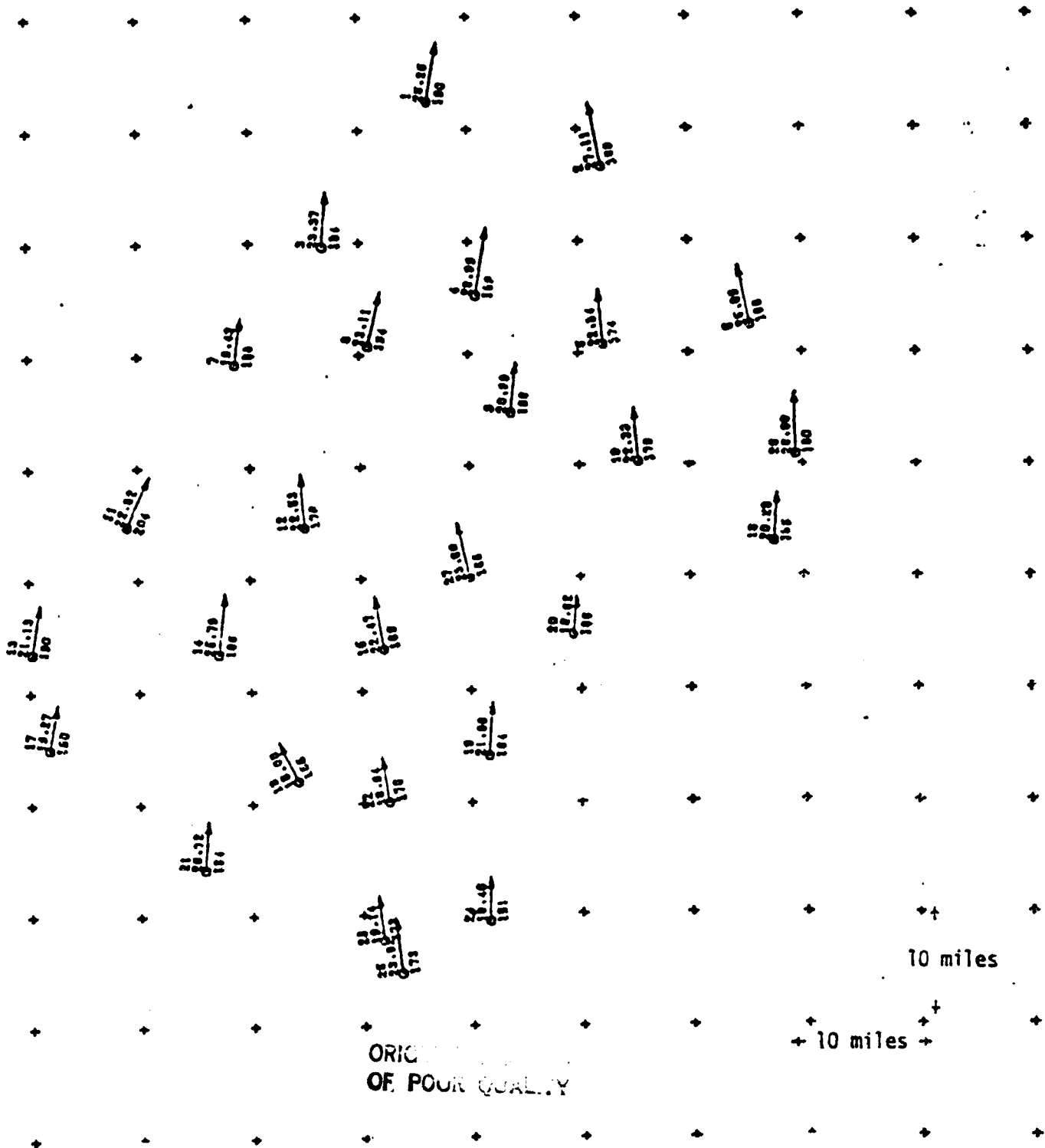

Figure 9j. Wind speed and direction maps for a front for the SESAME array
for 20 minute periods from 3:40 - 10:10 p.m.

73

WIND MAP AT 1900 PM

Figure 9k.   Wind speed and direction maps for a front for the SESAME array
for 20 minute periods from 3:40 - 10:10 p.m.

74

1900

Figure 91. Wind speed and direction maps for a front for the SESAME array
for 20 minute periods from 3:40 - 10:10 p.m.

Figure 9m. Wind speed and direction maps for a front for the SESAME array for 20 minute periods from 3:40 - 10:10 p.m.

Figure 9n. Wind speed and direction maps for a front for the SESAME array for
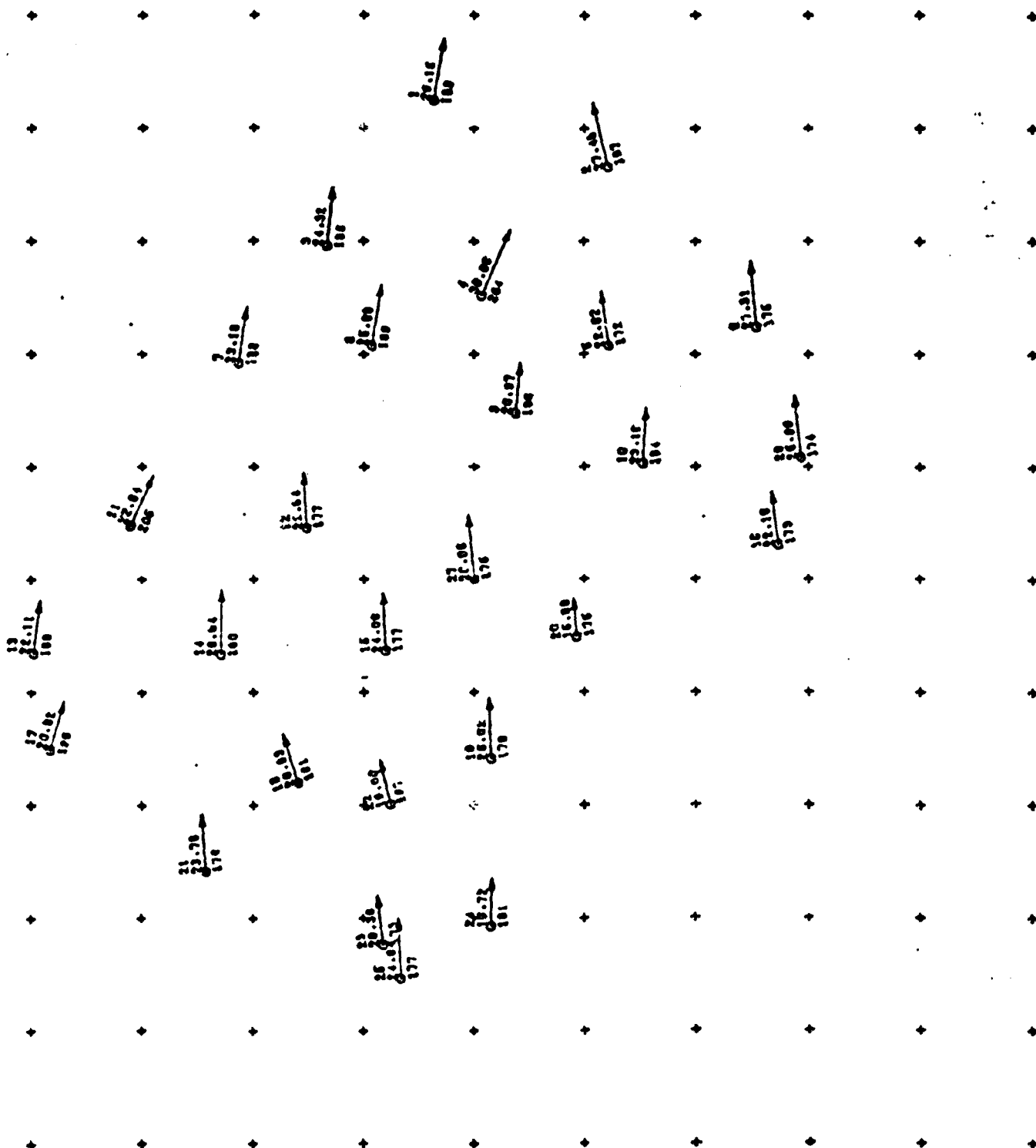20 minute periods from 3:40 - 10:10 p.m.

1930

Figure 9o. Wind speed and direction maps for a front for the SESAME array for
20 minute periods from 3:40 - 10:10 p.m.

1940

Figure 9p.   Wind speed and direction maps for a front for the SESAME array for
20 minute periods from 3:40 - 10:10 p.m.

1950

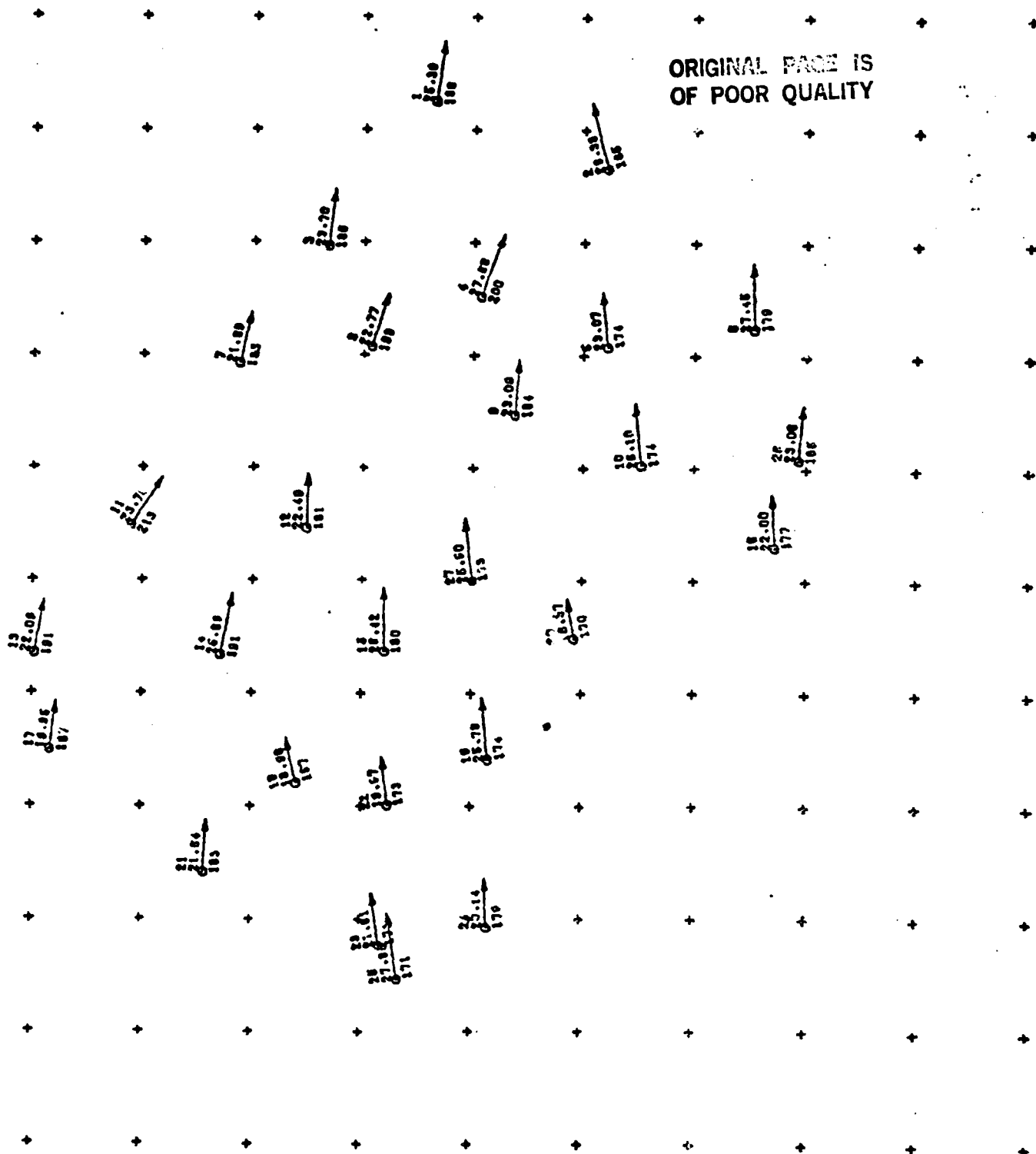
Figure 9q.   Wind speed and direction maps for a front for the SESAME array for
20 minute periods from 3:40 - 10:10 p.m.

80

Figure 9r.   Wind speed and direction maps for a front for the SESAME array for
20 minute periods from 3:40 - 10:10 p.m.

2010

Figure 9s. Wind speed and direction maps for a front for the SESAME array for
20 minute periods from 3:40 - 10:10 p.m.

2020

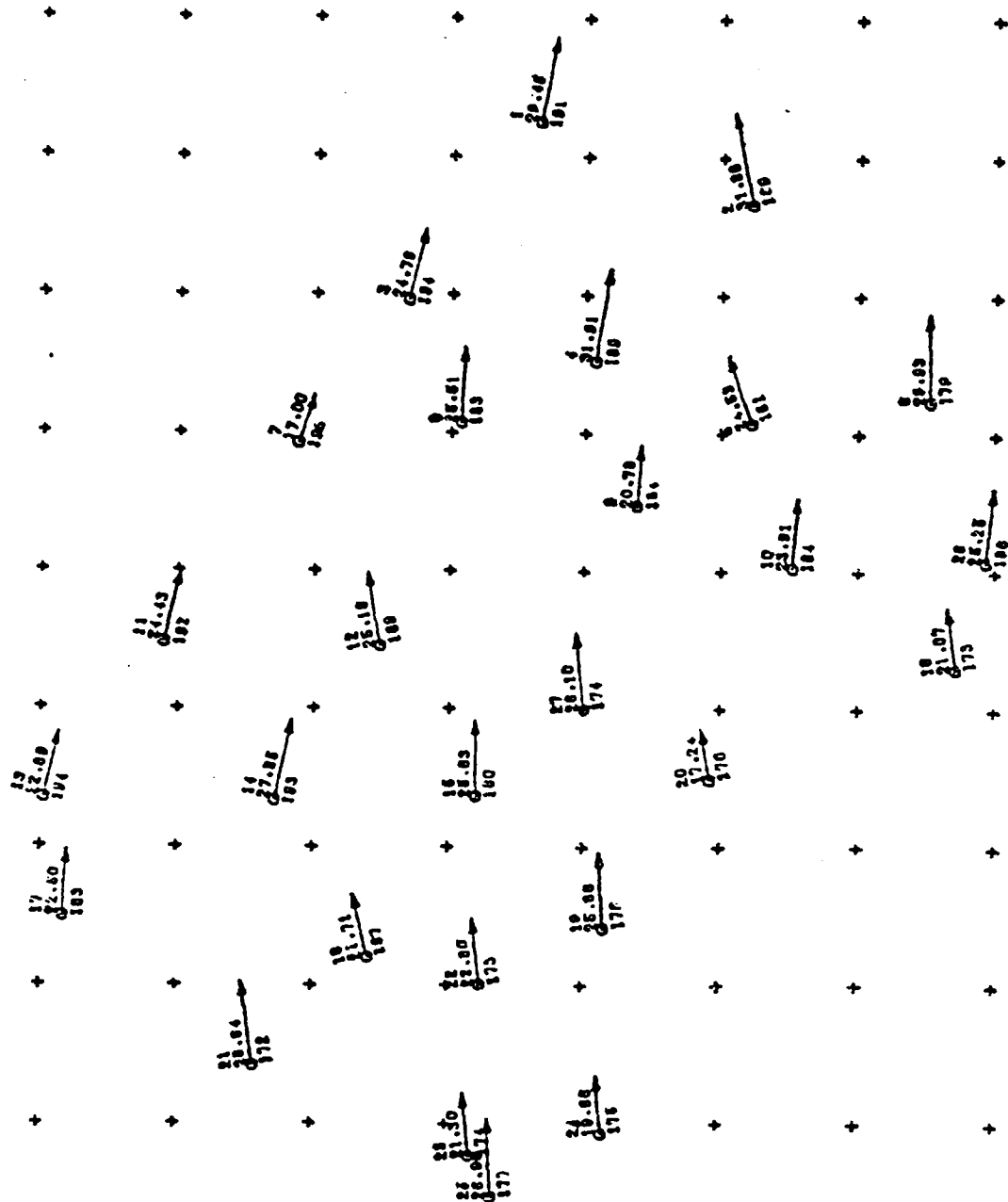Figure 9t. Wind speed and direction maps for a front for the SESAME array for 20 minute periods from 3:40 - 10:10 p.m.

2030

Figure 9u. Wind speed and direction maps for a front for the SESAME array for
20 minute periods from 3:40 - 10:10 p.m.

84

2040
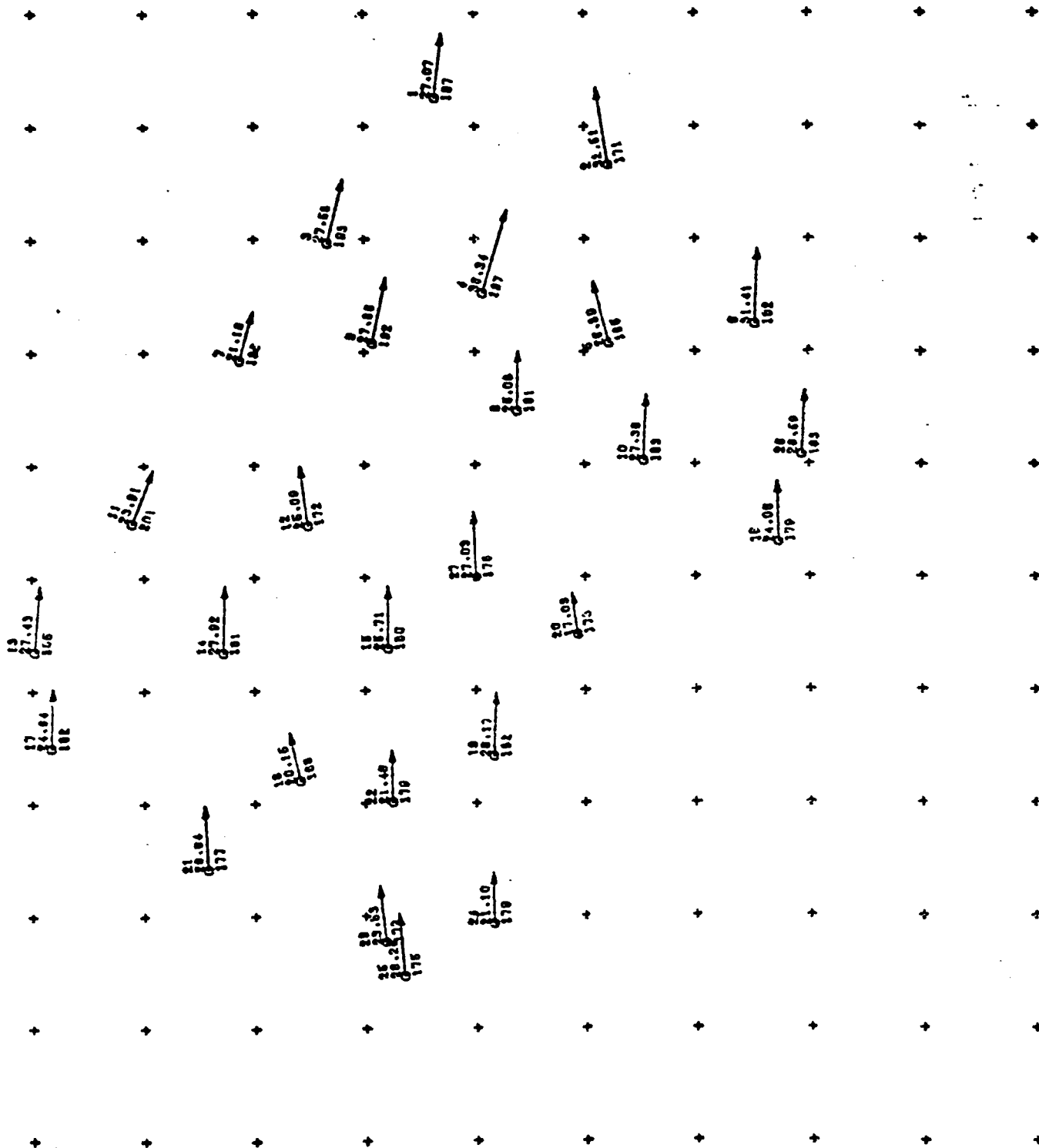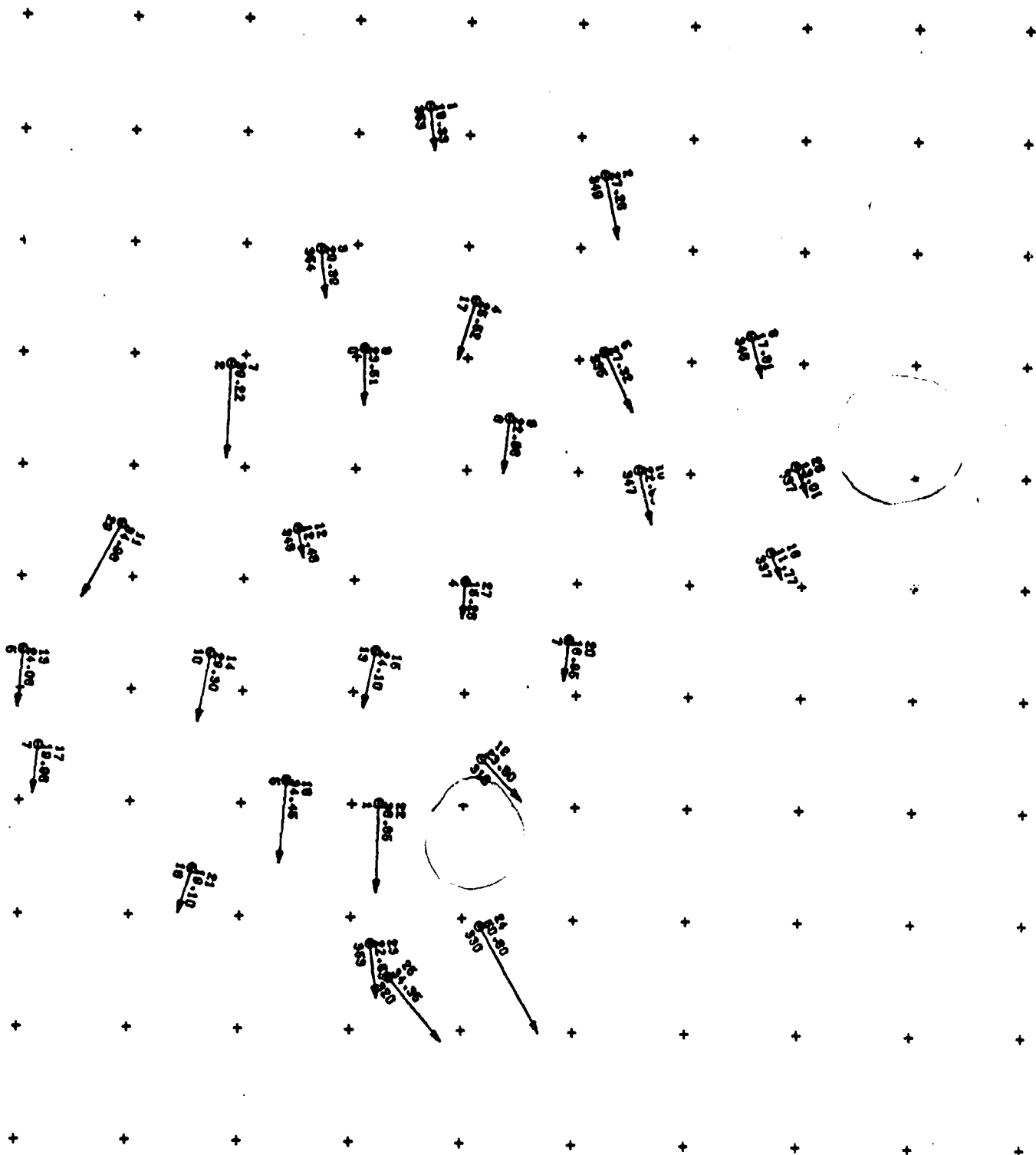
Figure 9v.   Wind speed and direction maps for a front for the SESAME array for
20 minute periods from 3:40 - 10:10 p.m.

2050
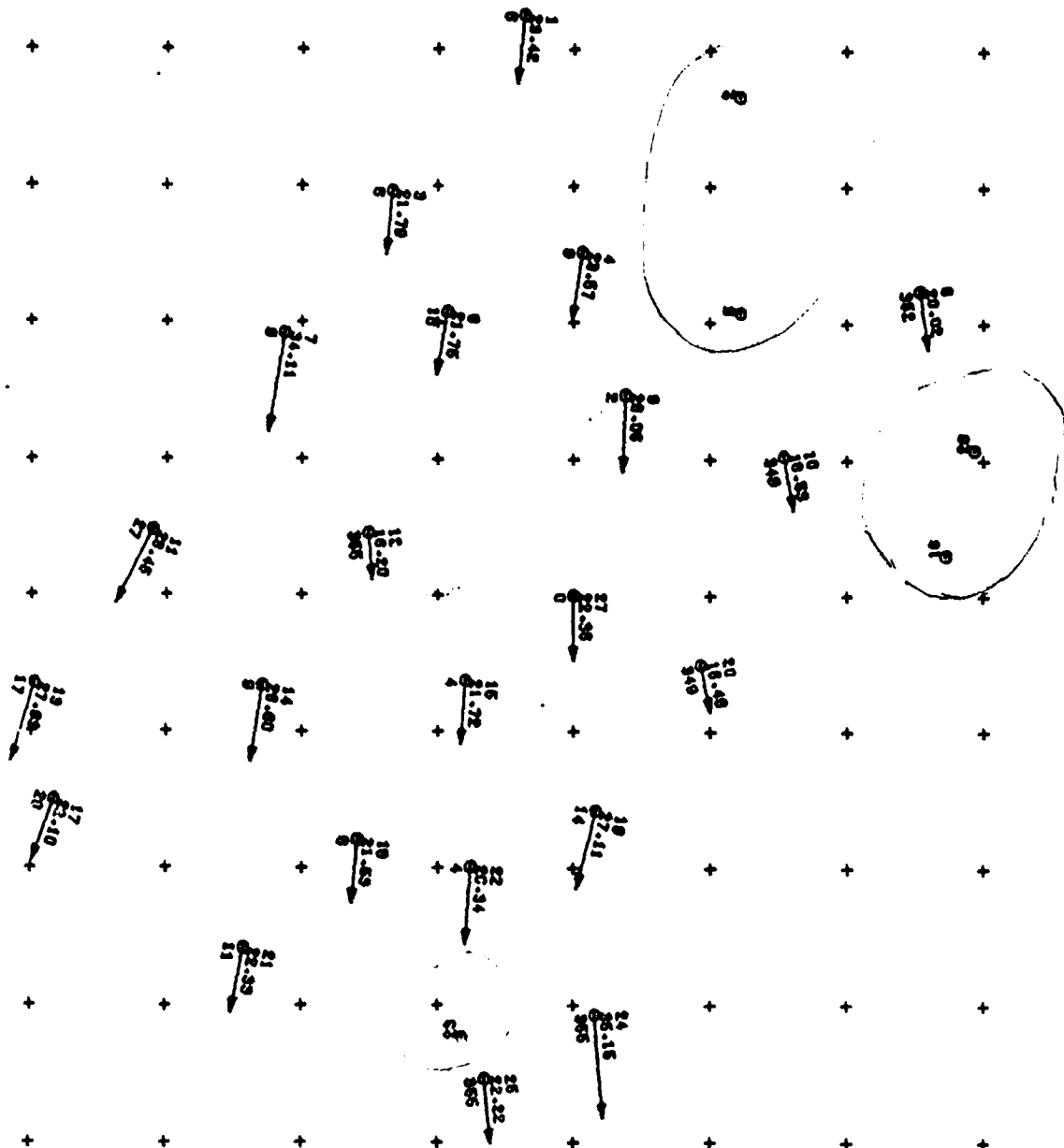
Figure 9w. Wind speed and direction maps for a front for the SESAME array for
20 minute periods from 3:40 - 10:10 p.m.

2100
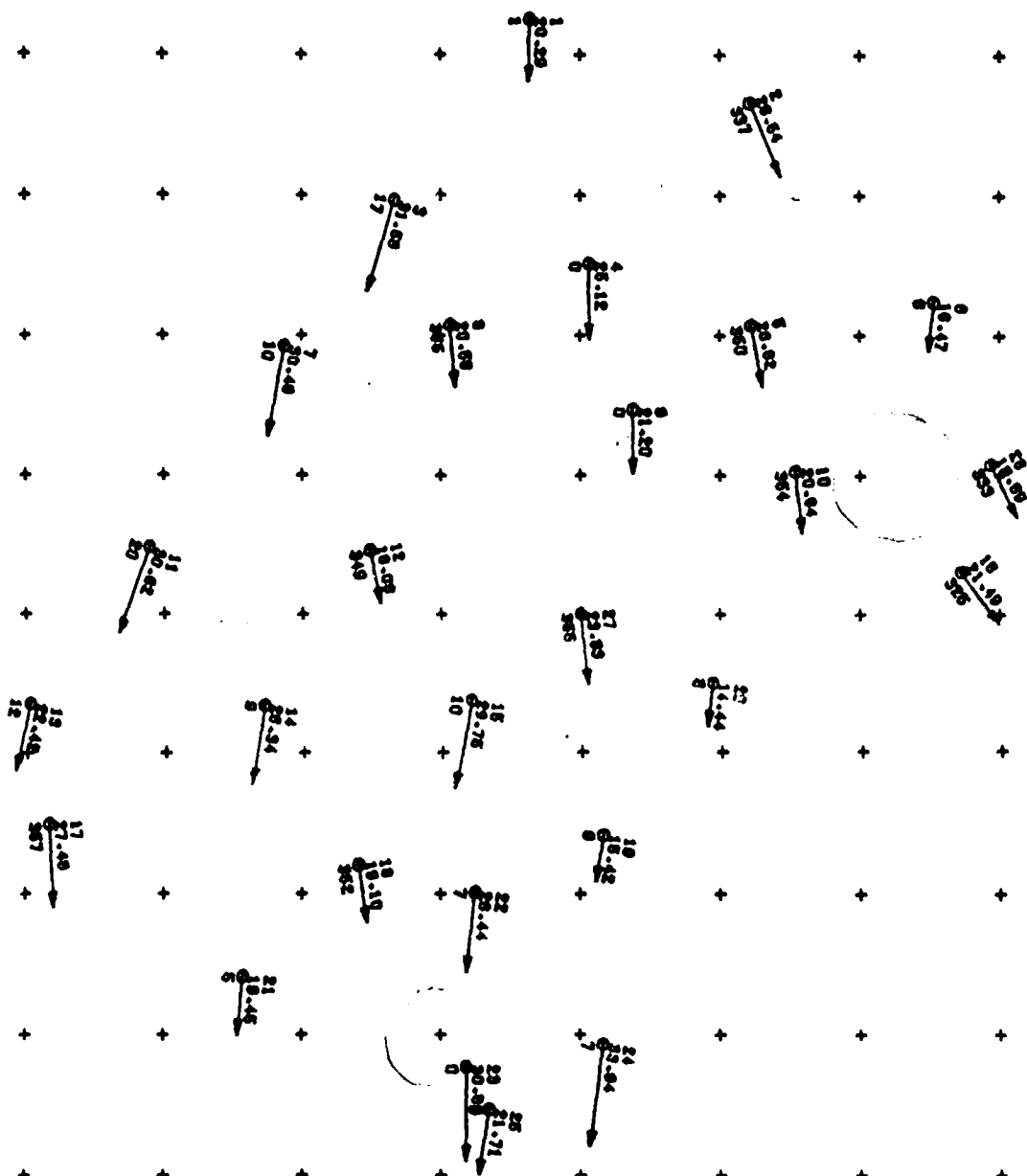
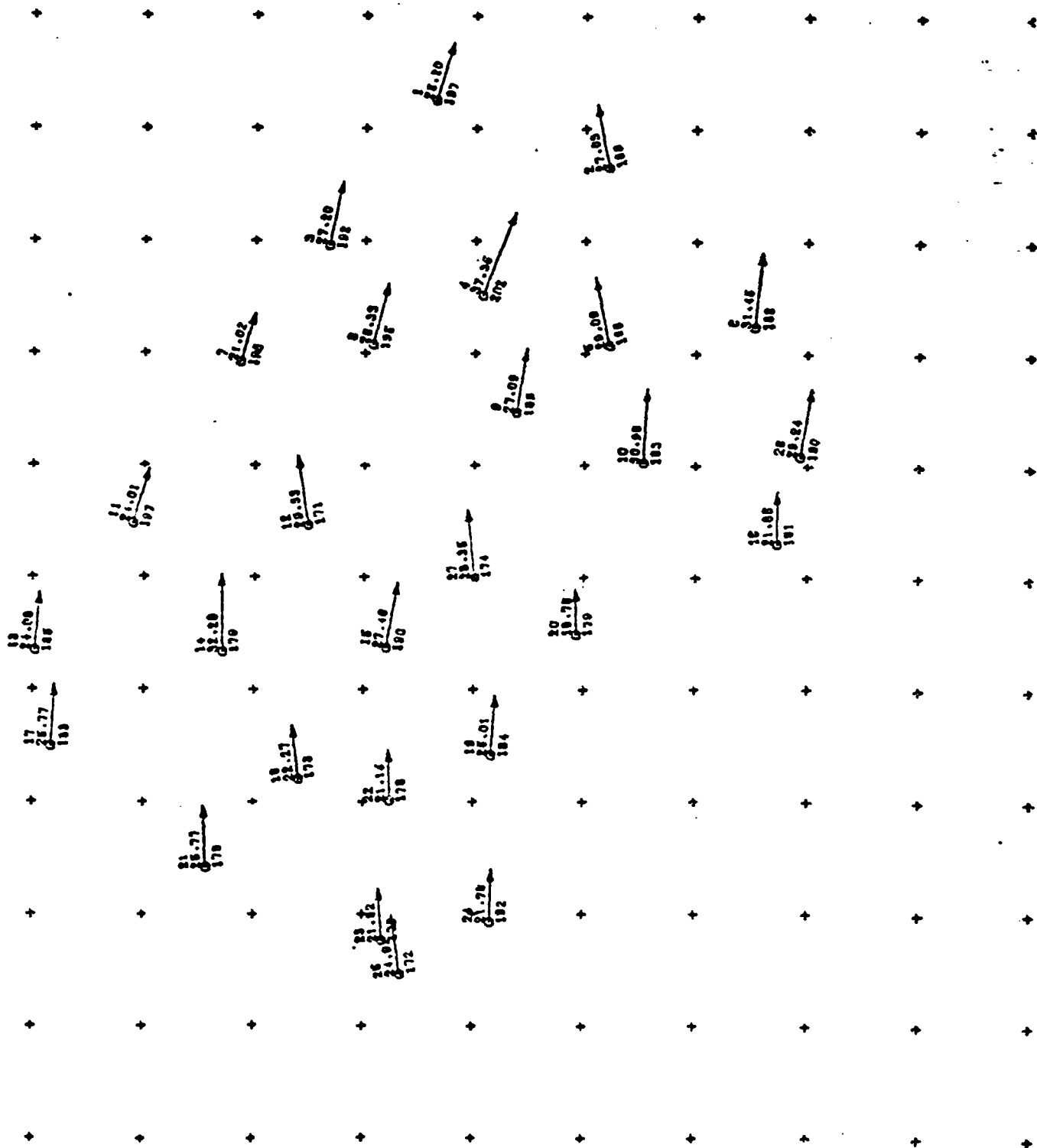Figure 9x. Wind speed and direction maps for a front for the SESAME array for 20 minute periods from 3:40 - 10:10 p.m.
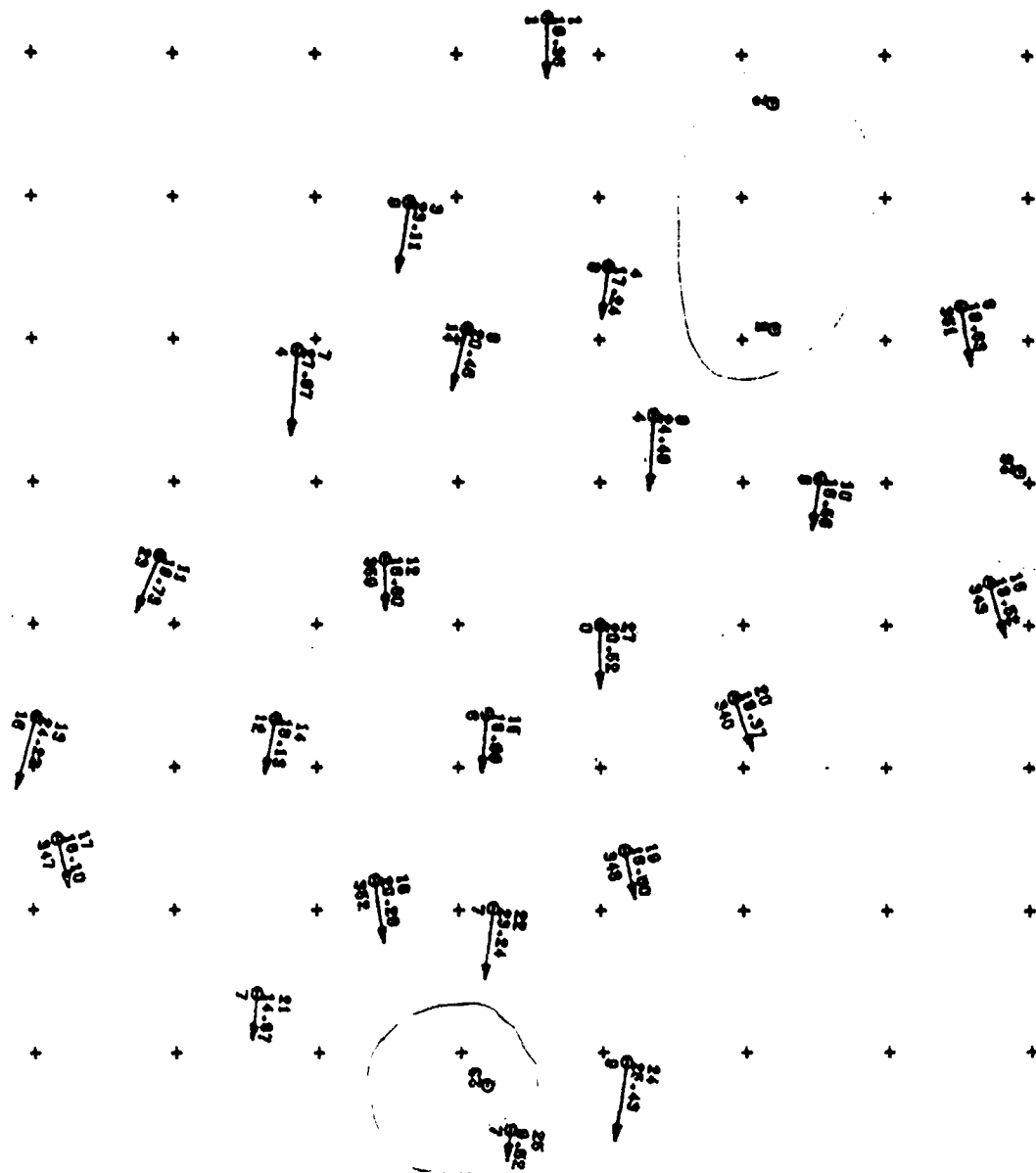
Figure 9y. Wind speed and direction maps for a front for the SESAME array for
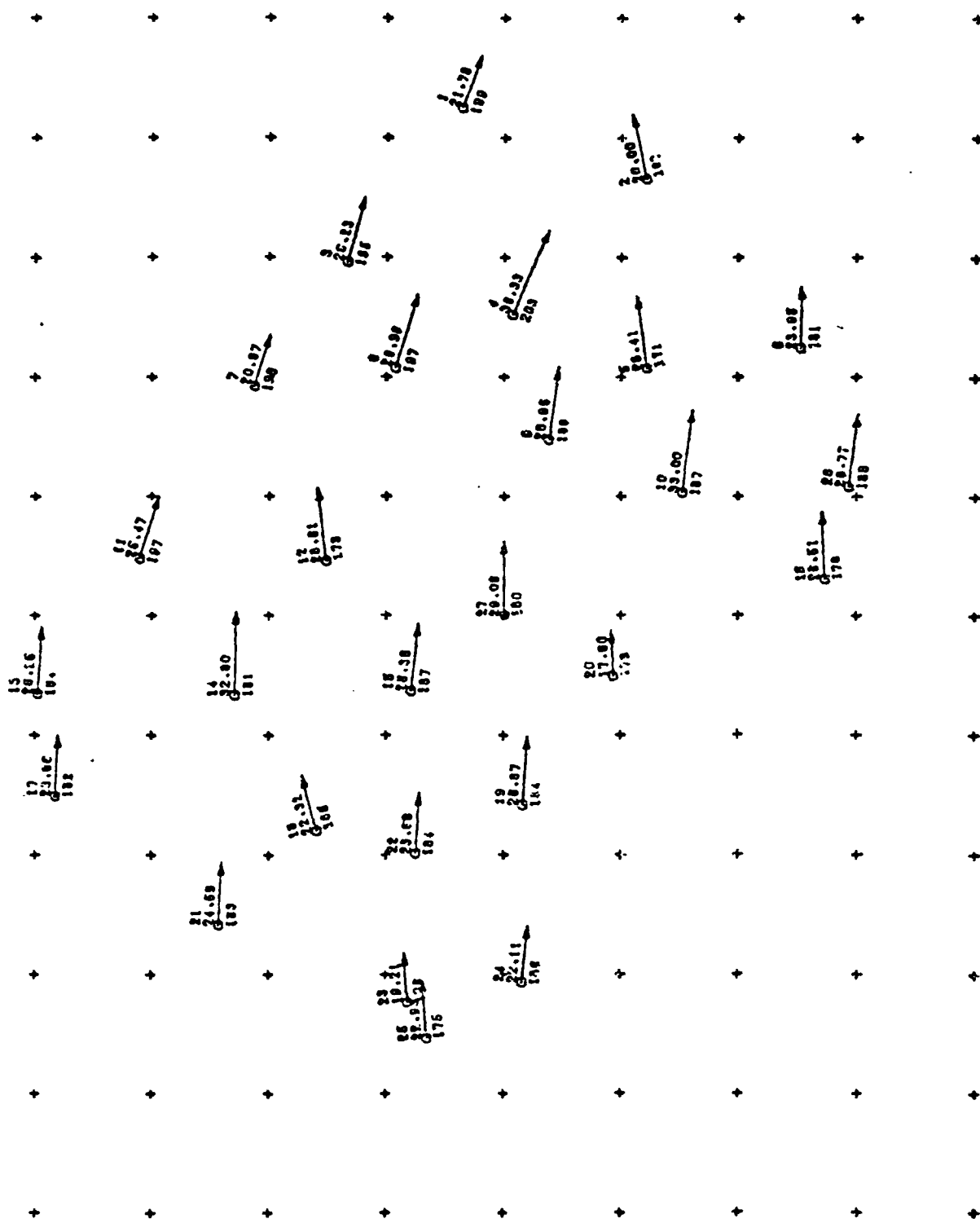20 minute periods from 3:40 - 10:10 p.m.

2120
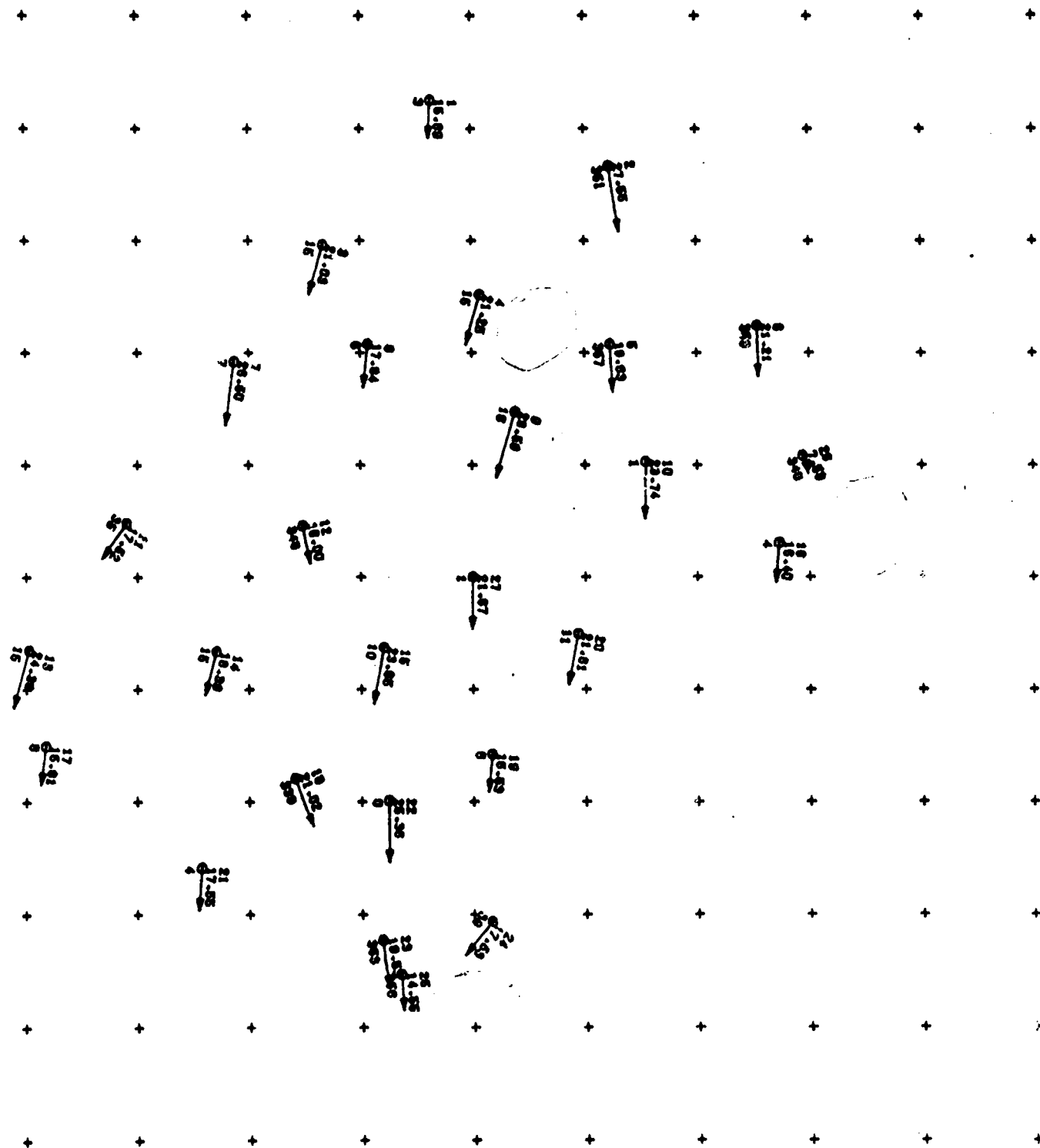
Figure 9z. Wind speed and direction maps for a front for the SESAME array for 20 minute periods from 3:40 - 10:10 p.m.
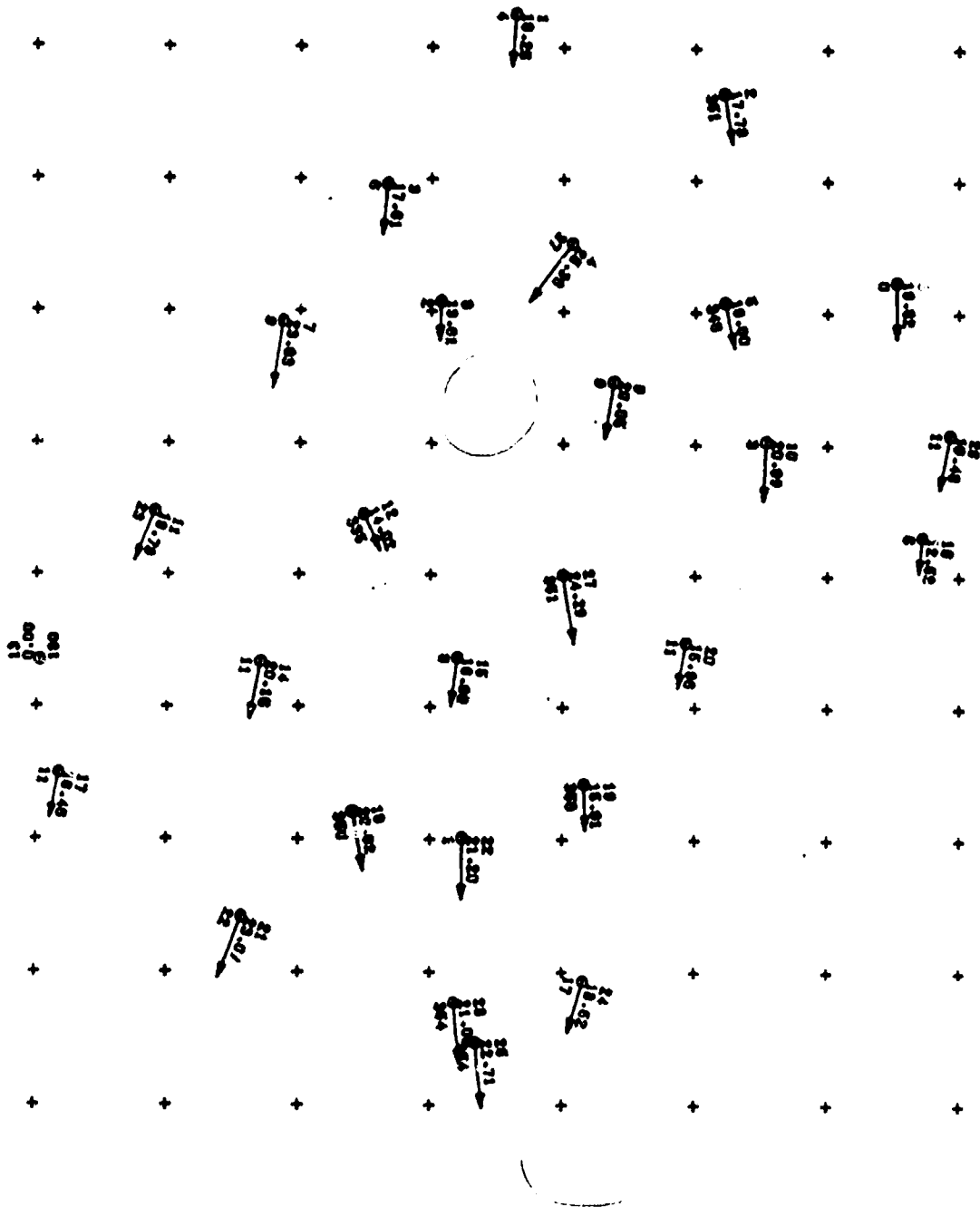
Figure 9aa.   Wind speed and direction maps for a front for the SESAME array for
              20 minute periods from 3:40 - 10:10 p.m.

2140
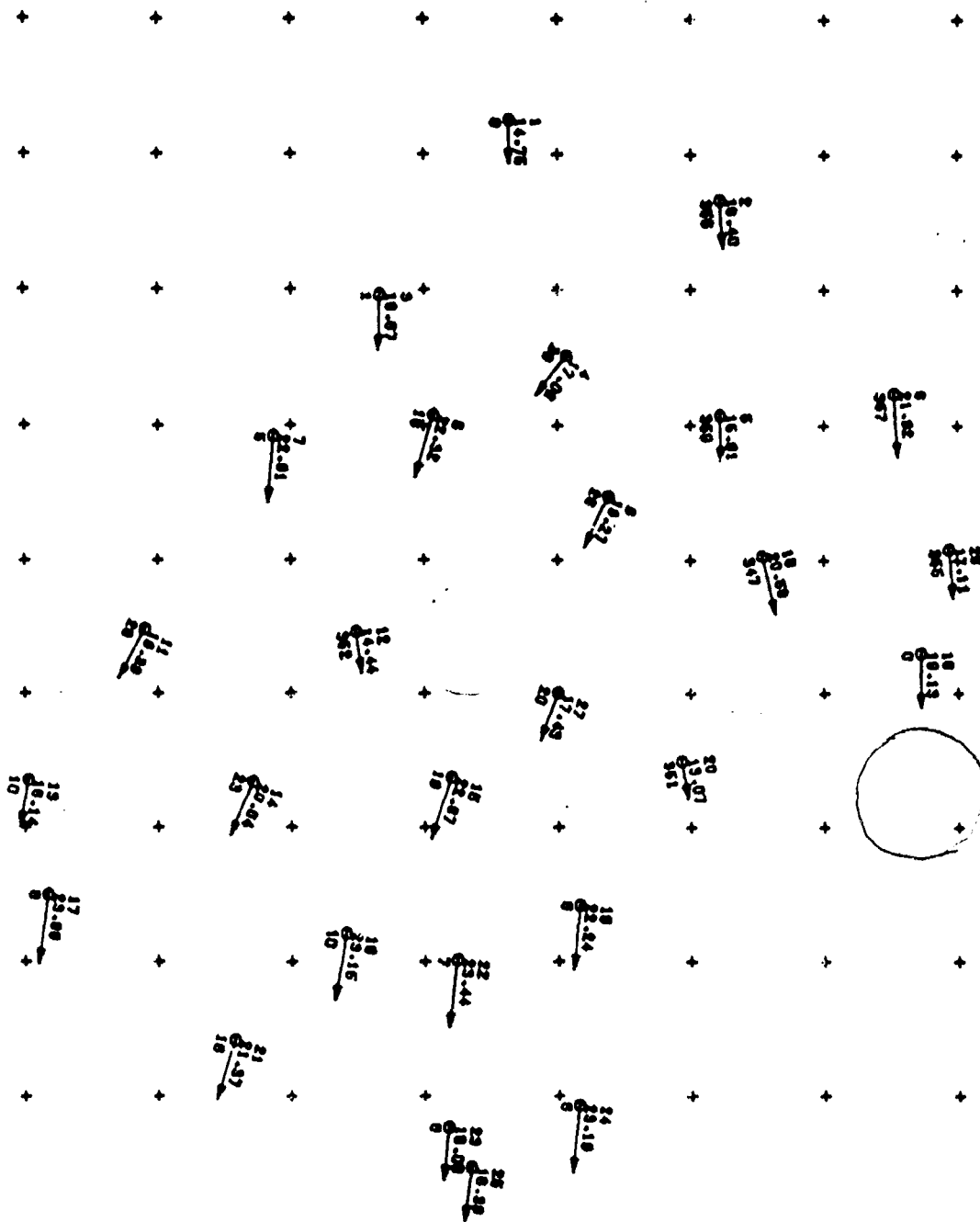
Figure 9bb.   Wind speed and direction maps for a front for the SESAME array for
20 minute periods from 3:40 - 10:10 p.m.

2150
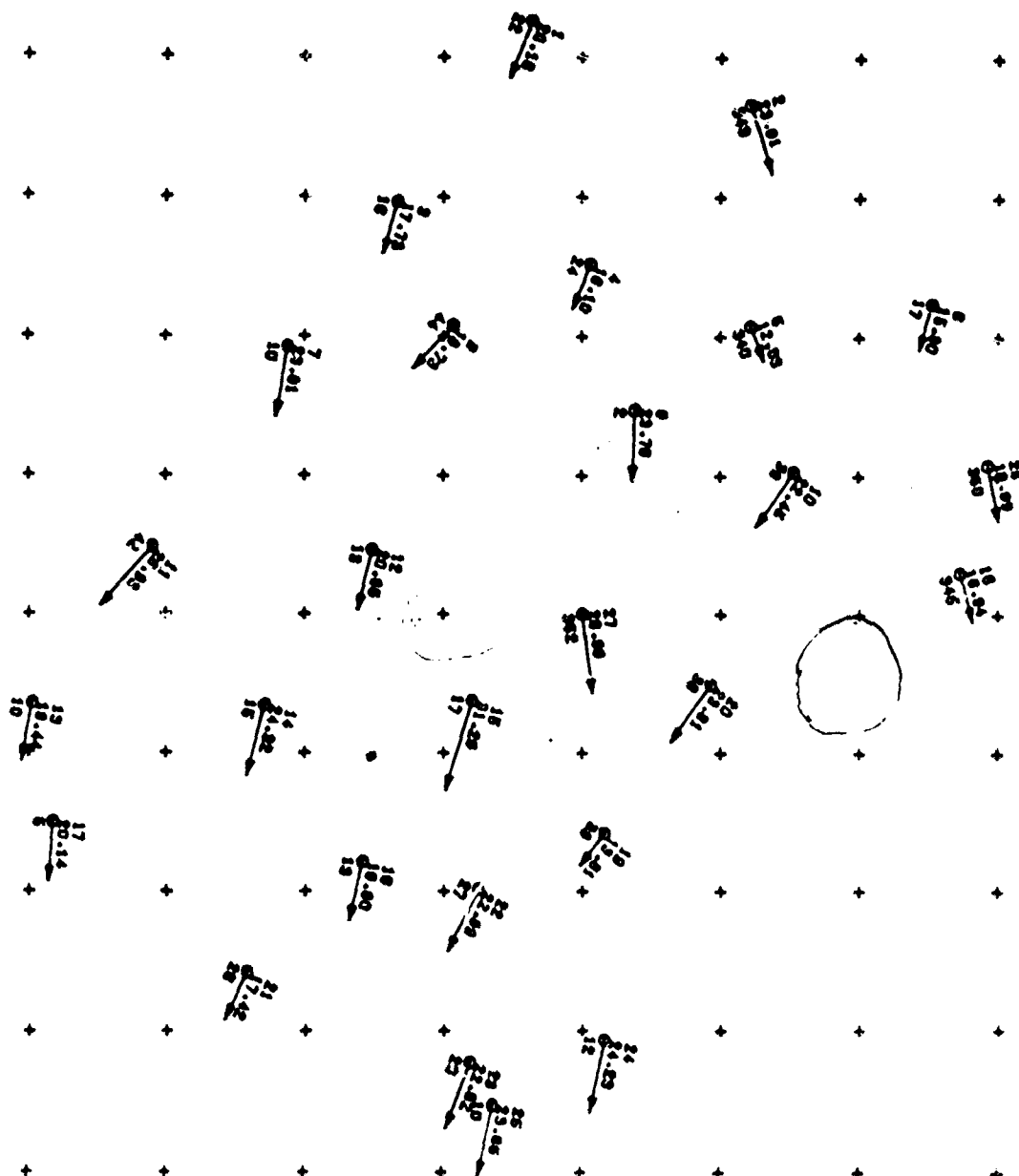
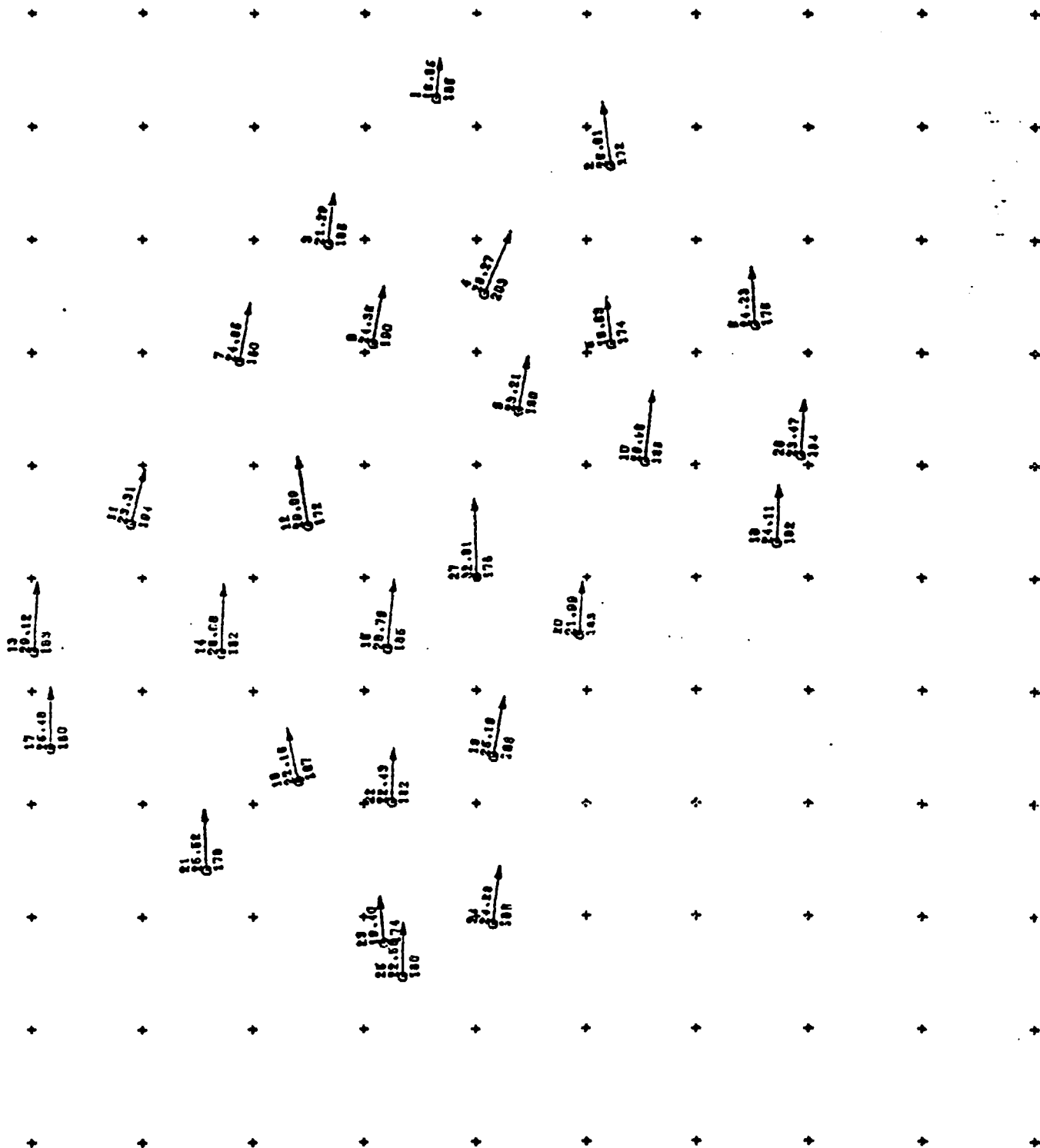

Figure 9cc. Wind speed and direction maps for a front for the SESAME array for 20 minute periods from 3:40 - 10:10 p.m.
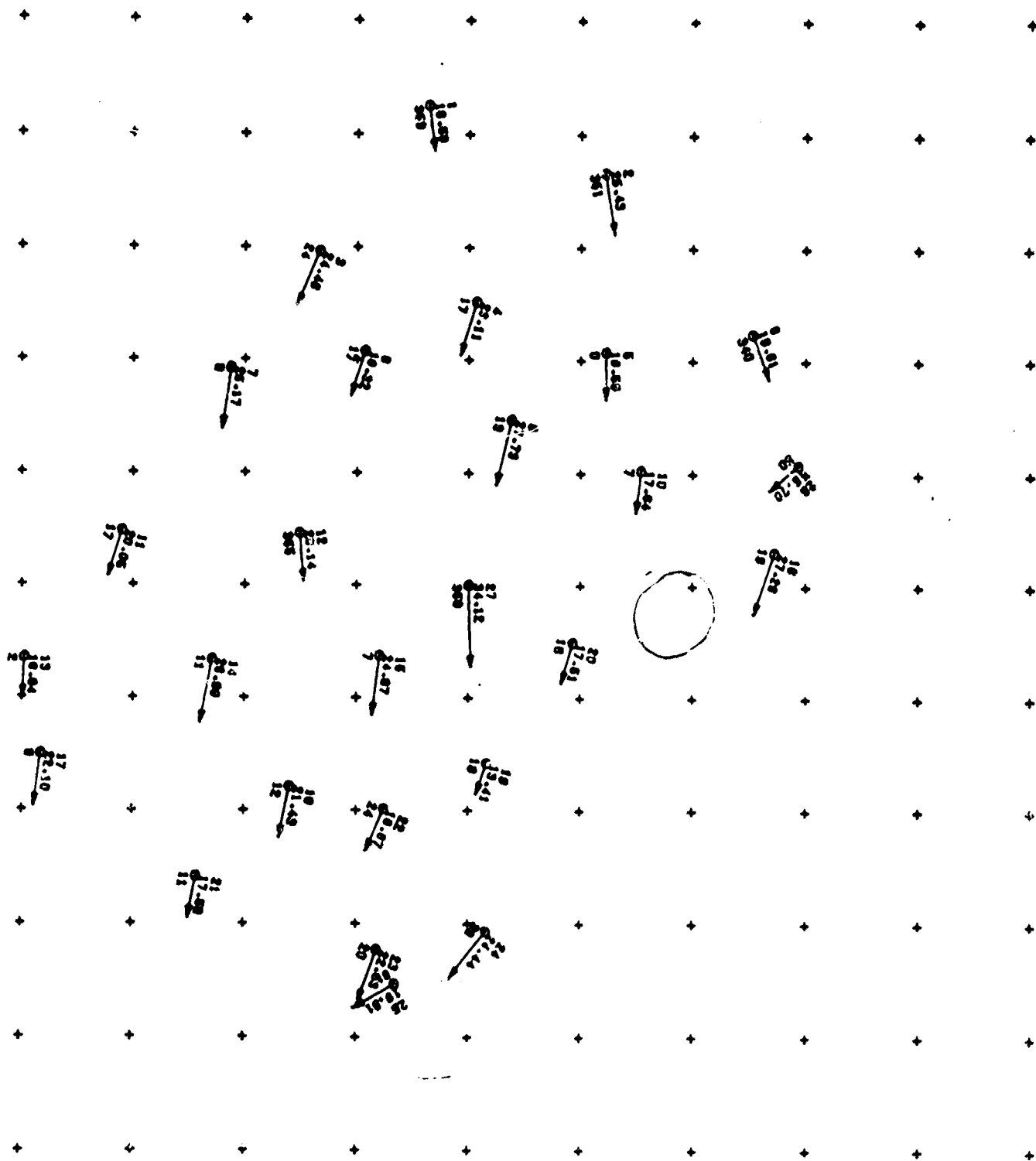
Figure 9dd. Wind speed and direction maps for a front for the SESAME array for
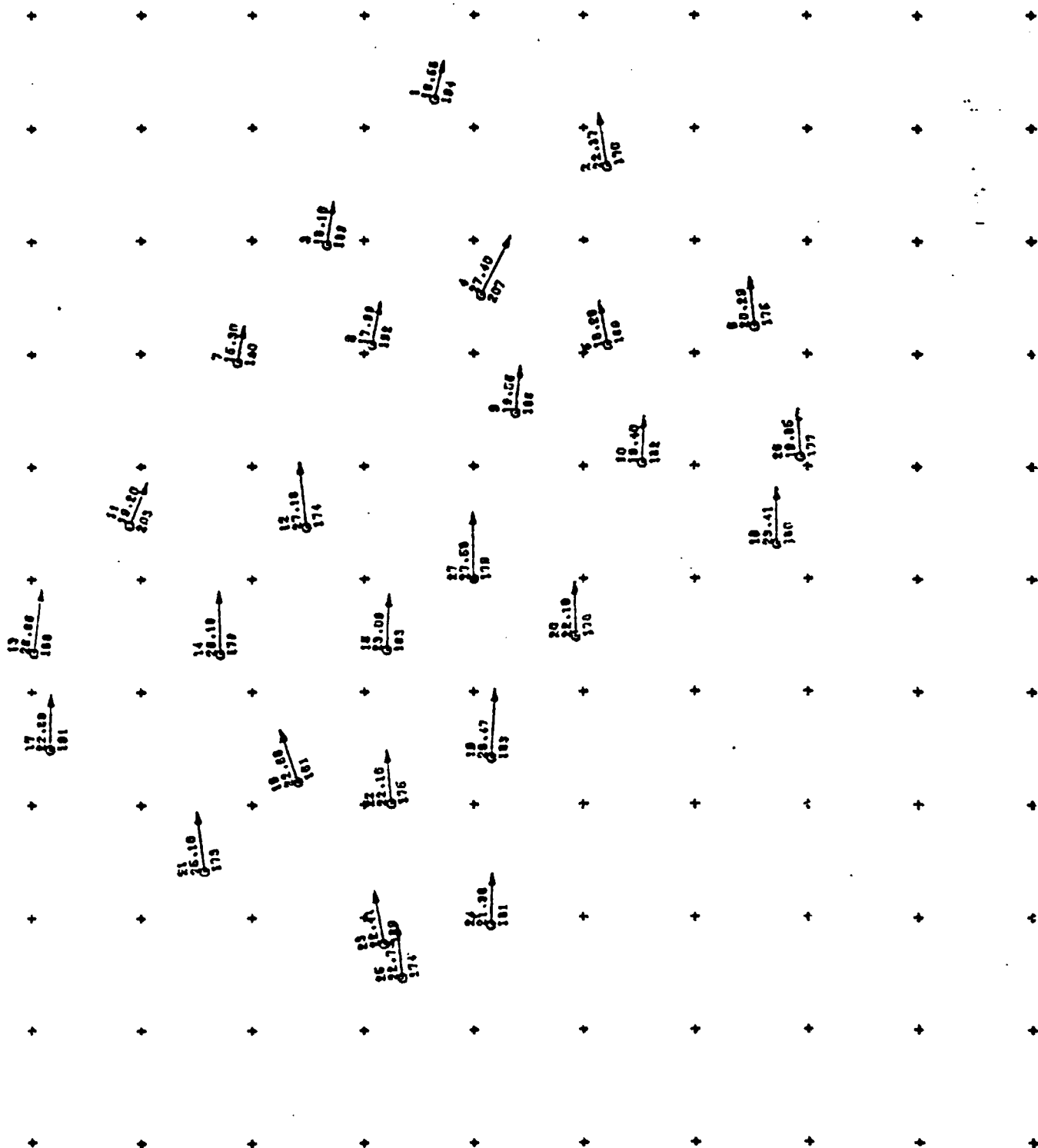20 minute periods from 3:40 - 10:10 p.m.

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2210
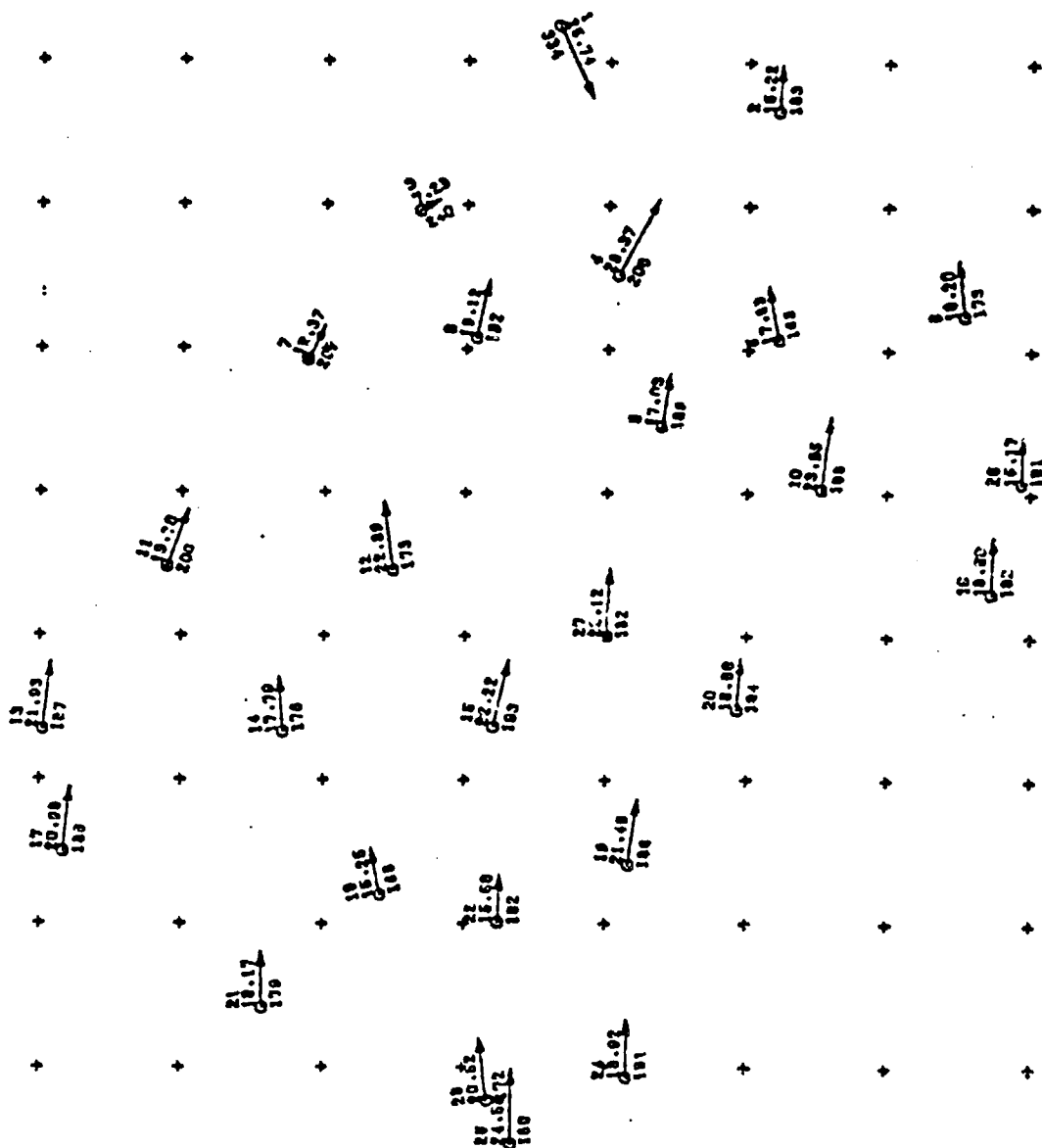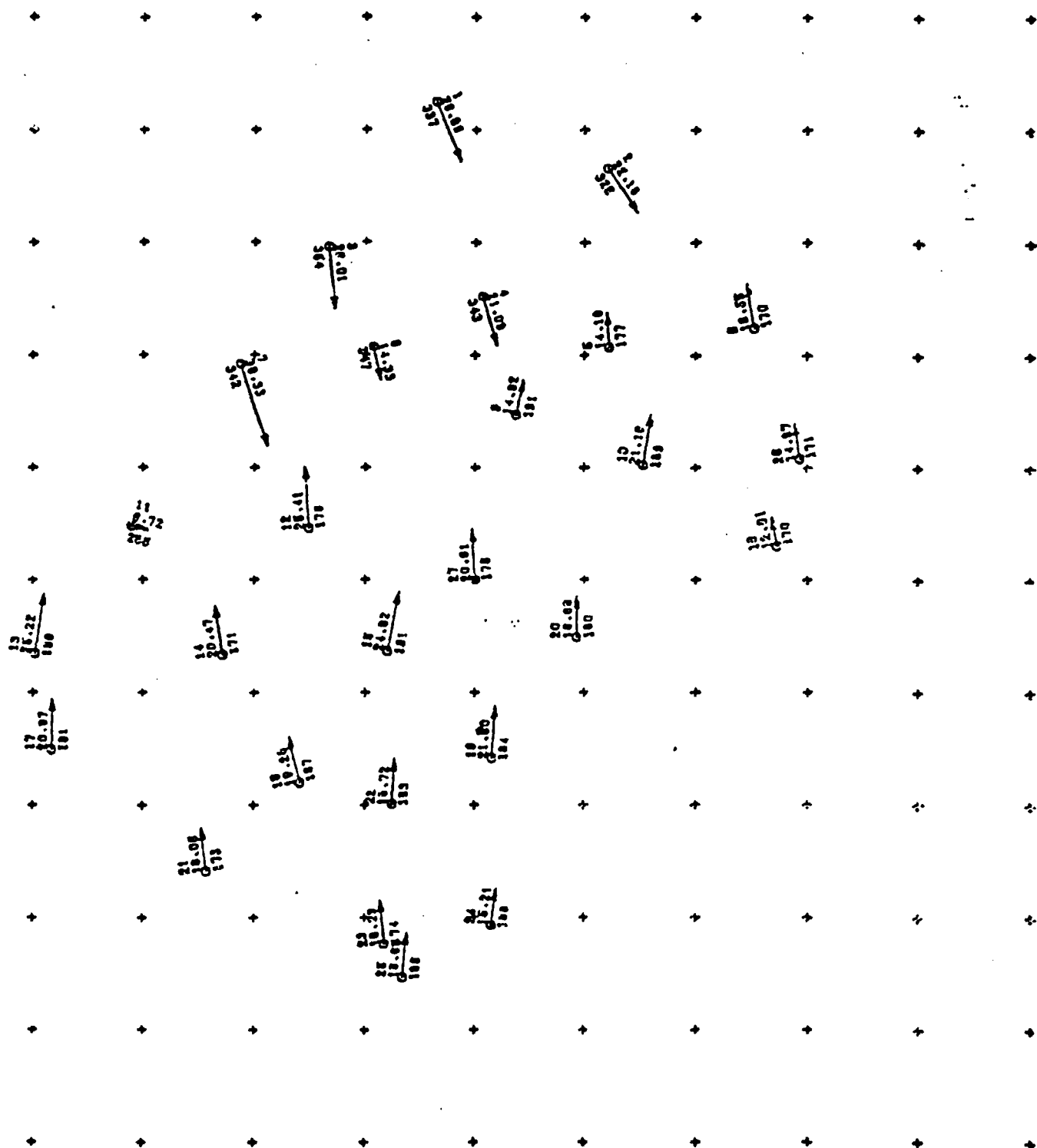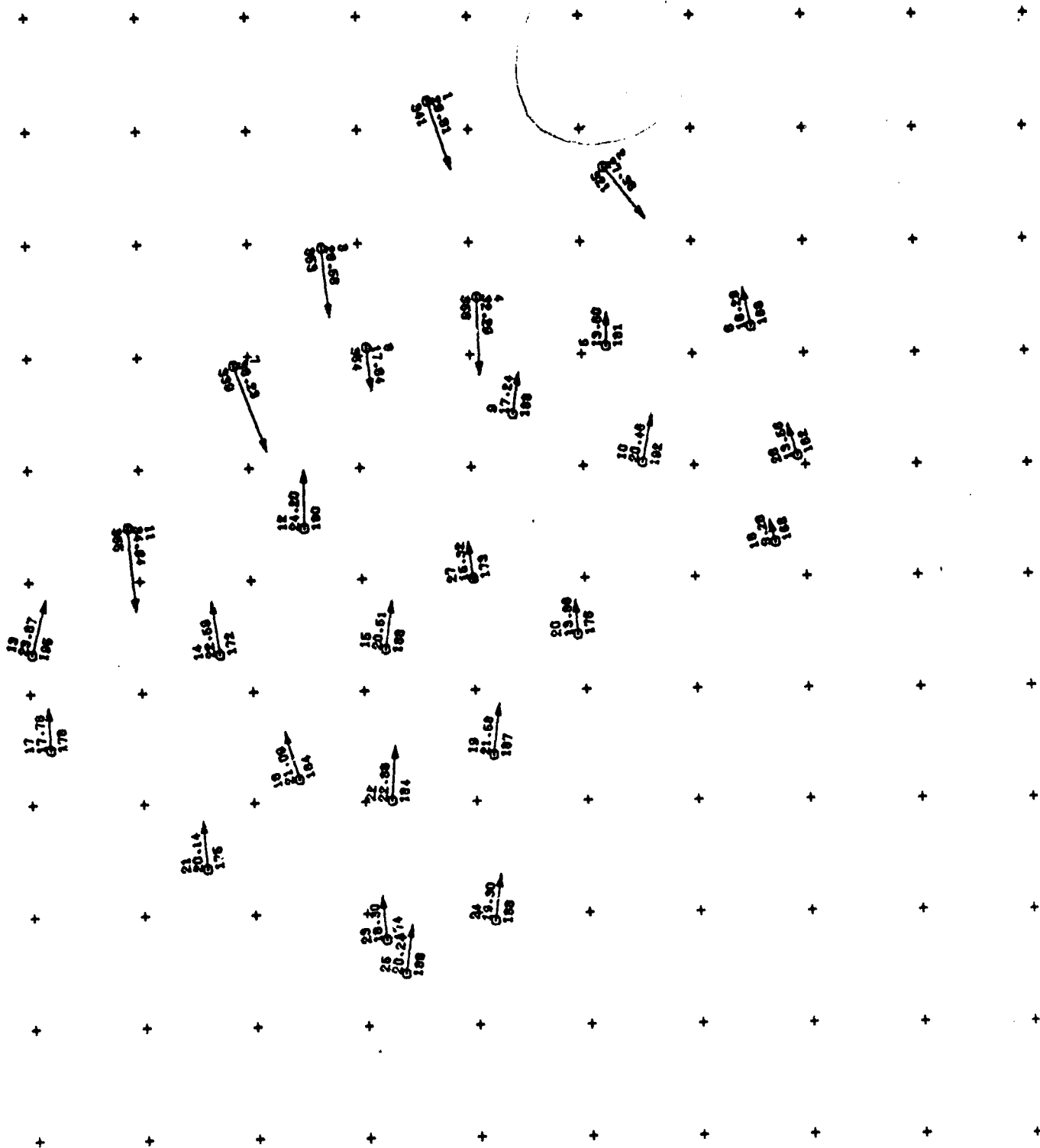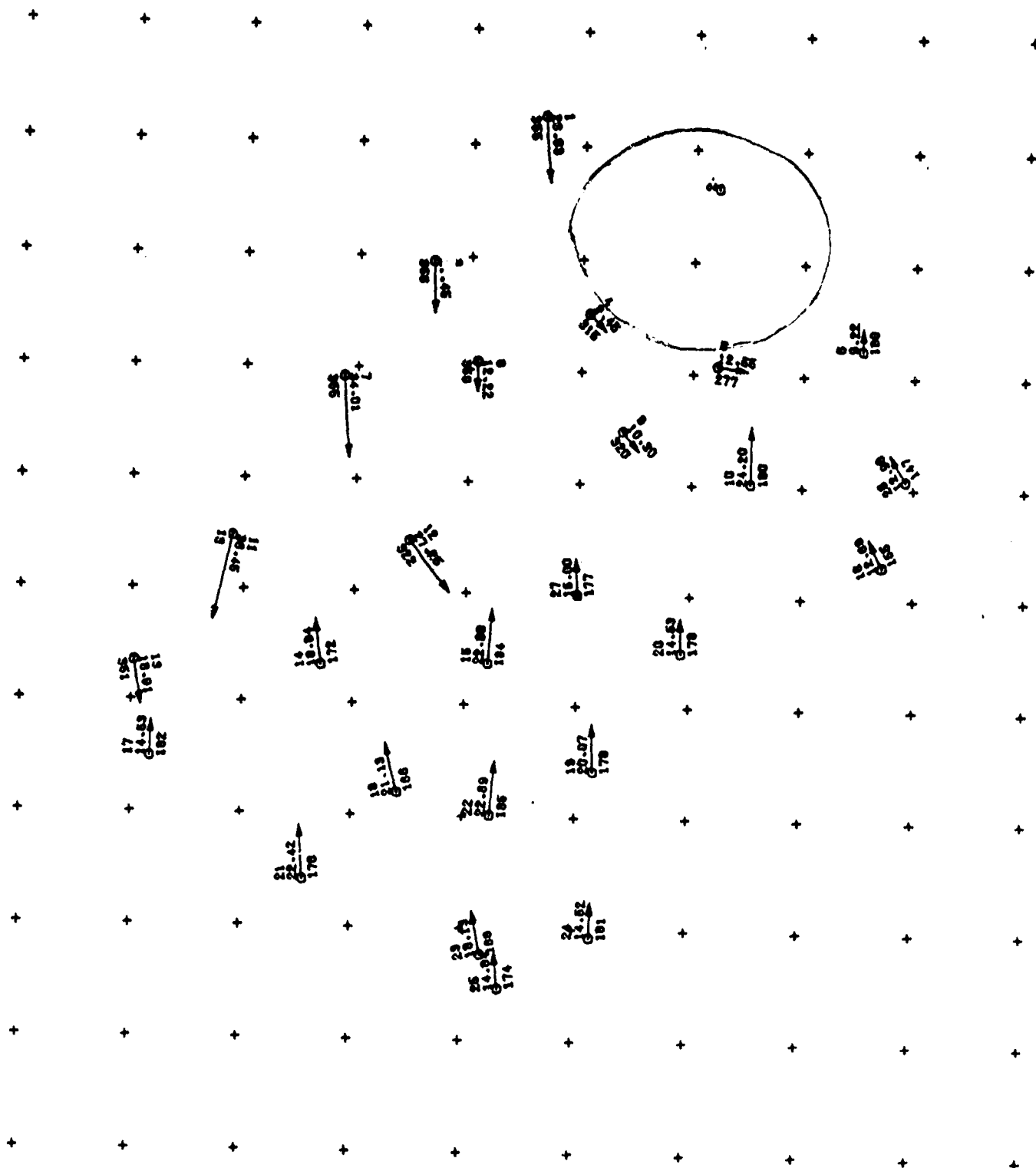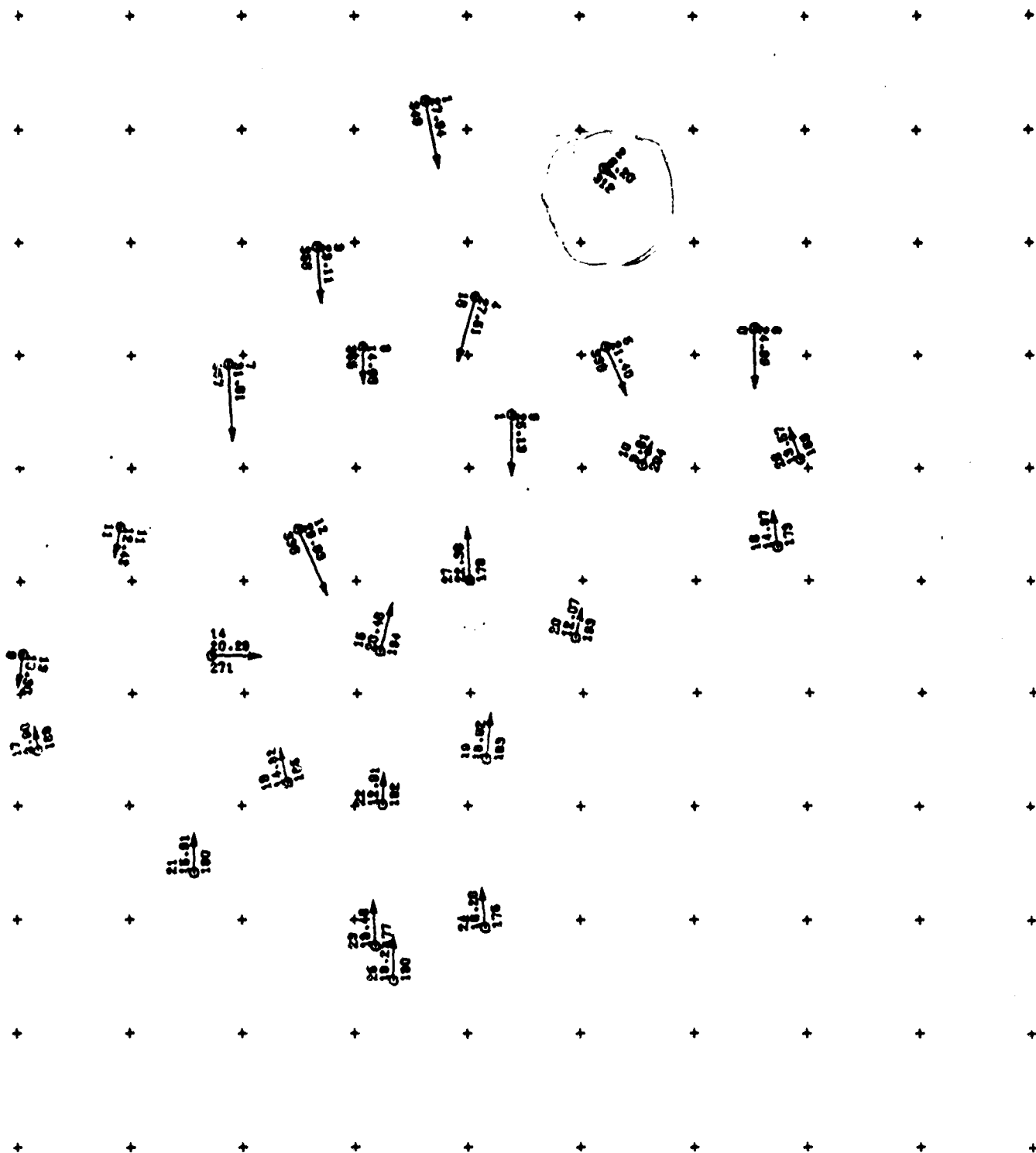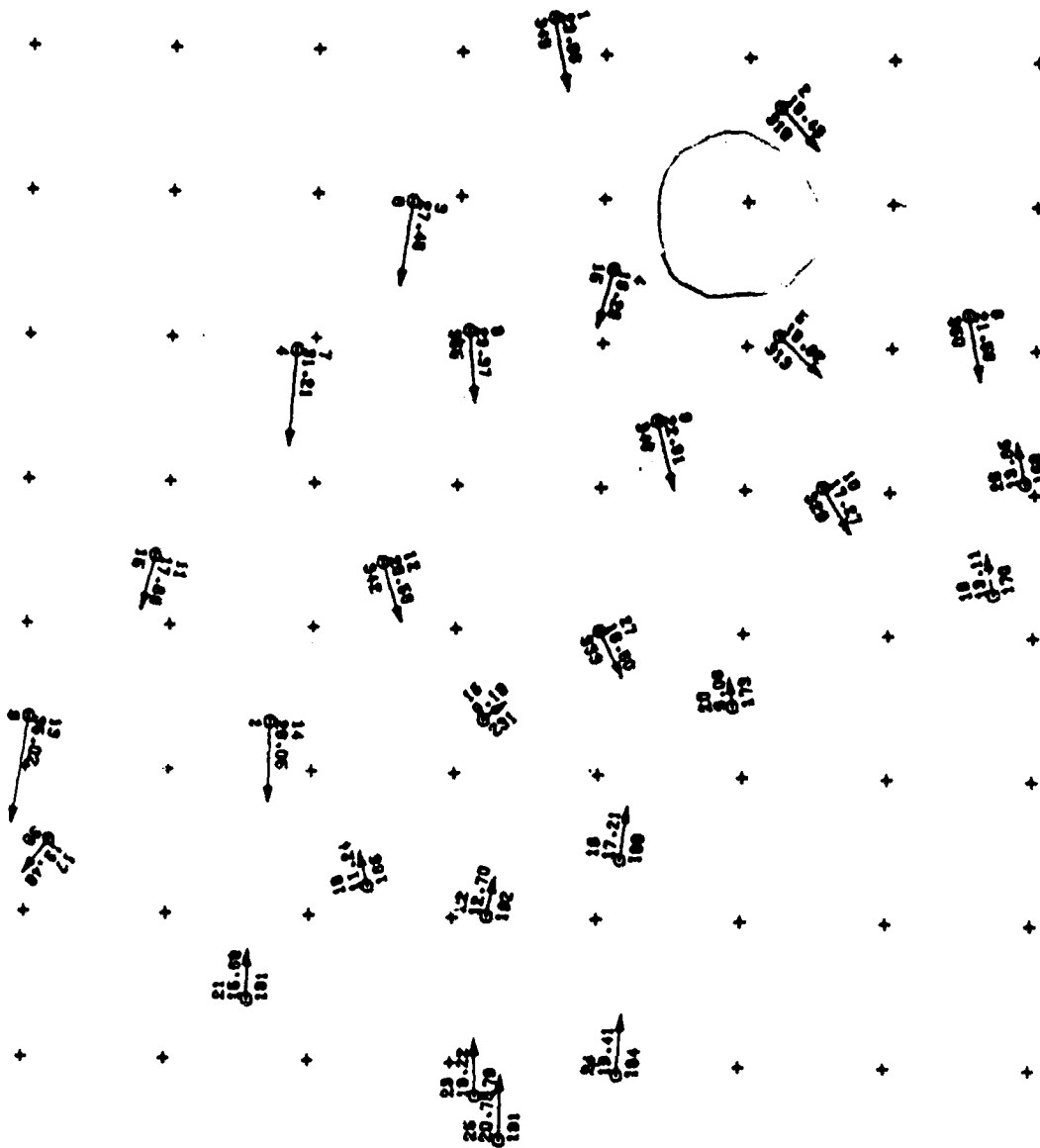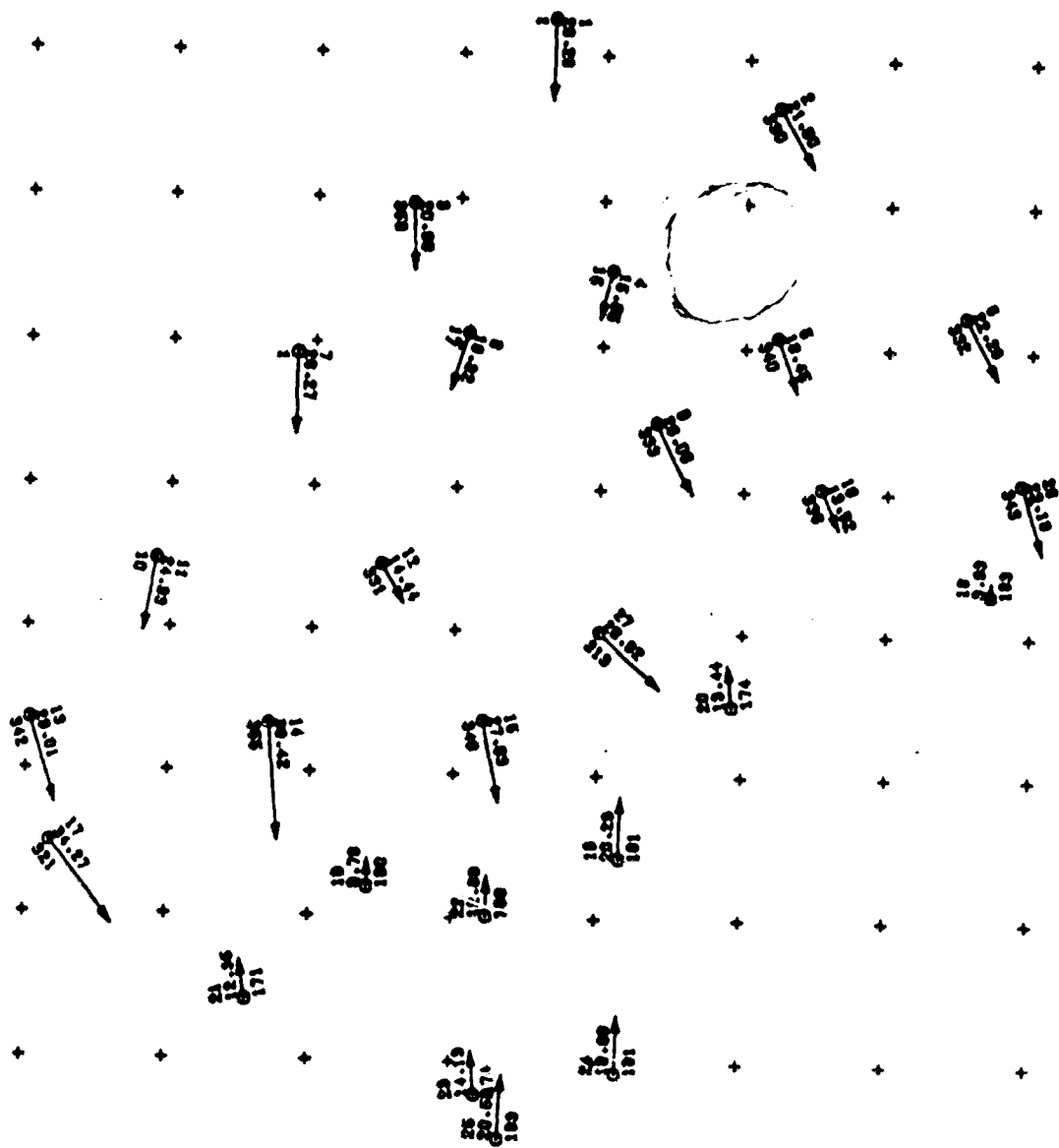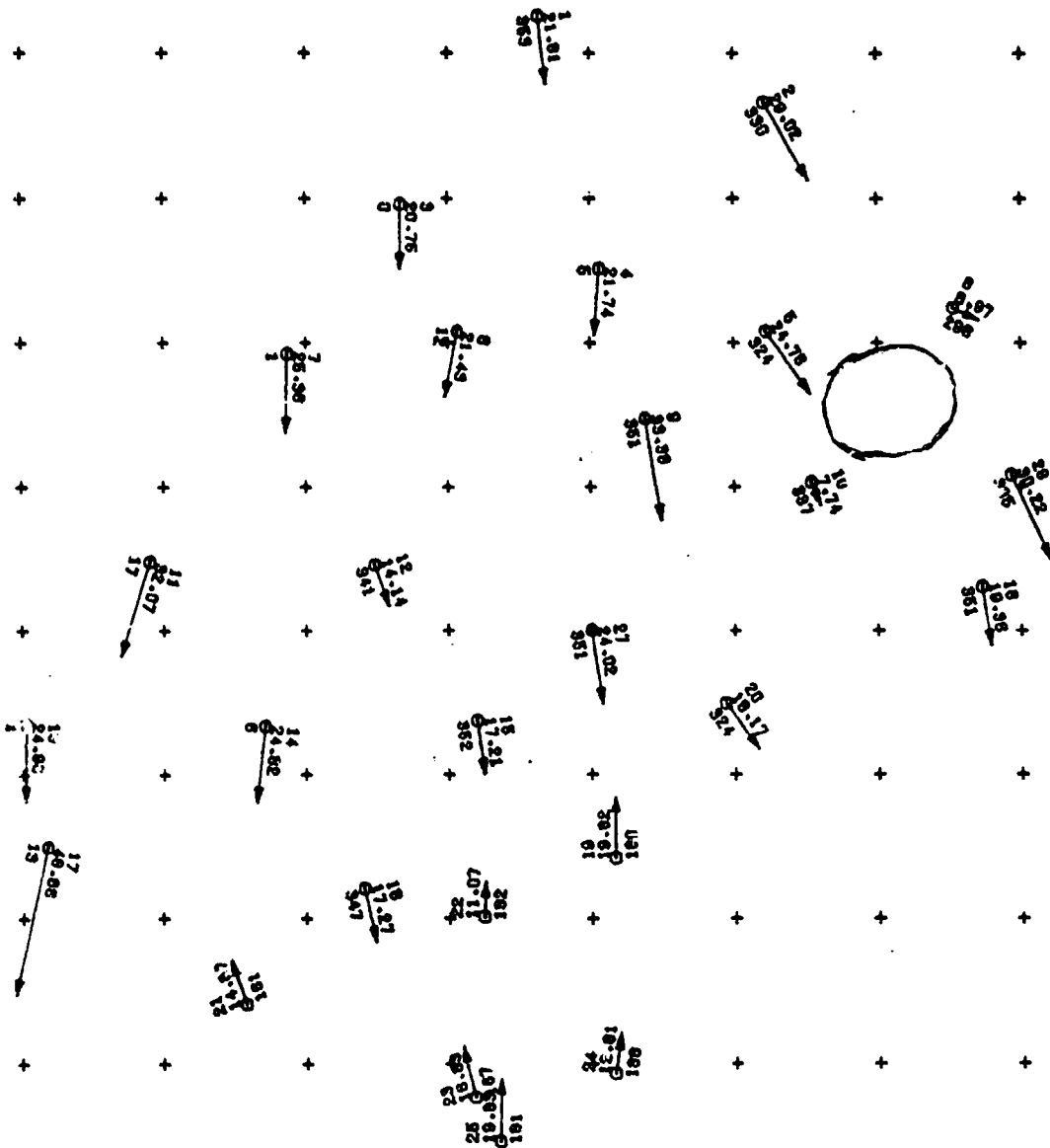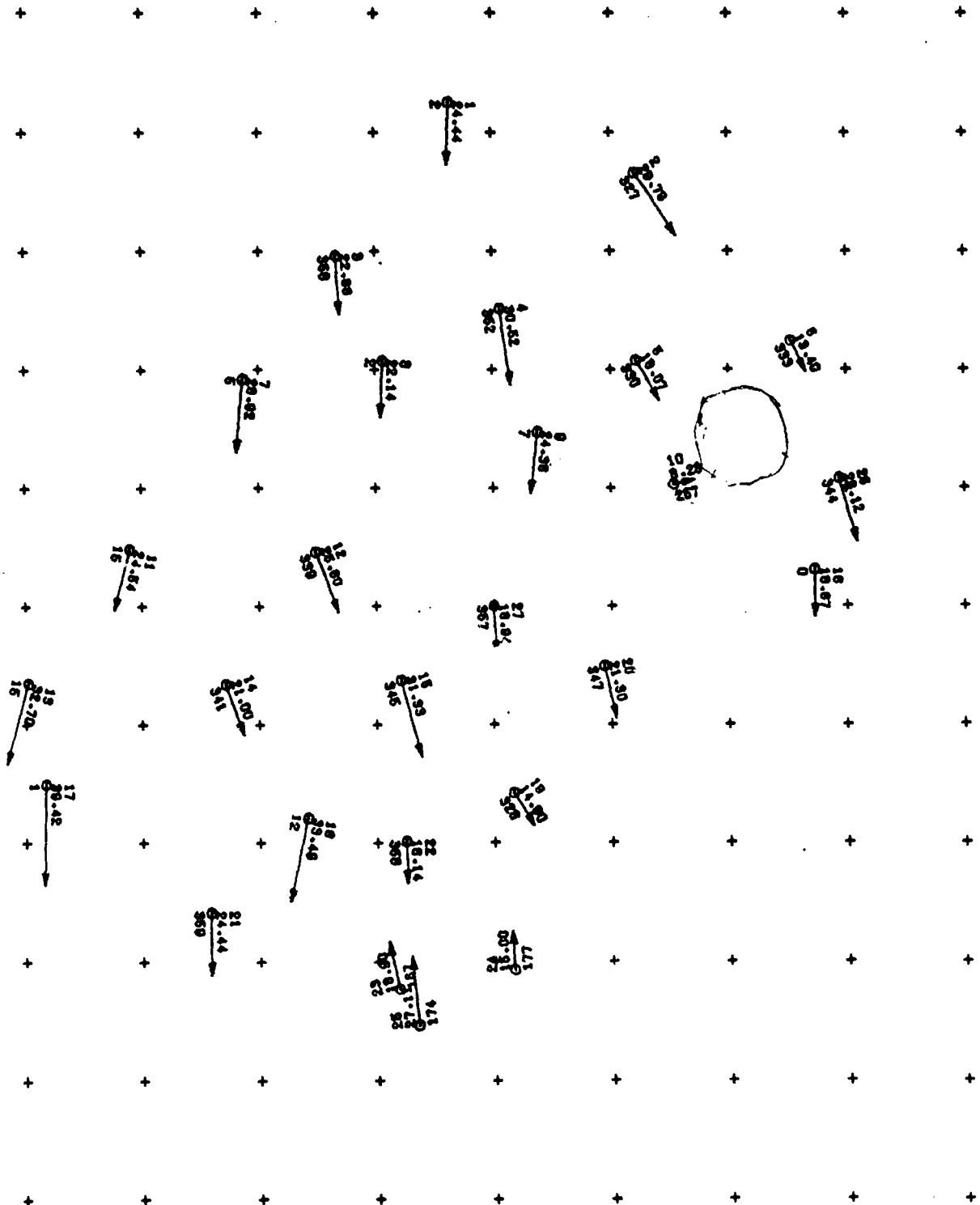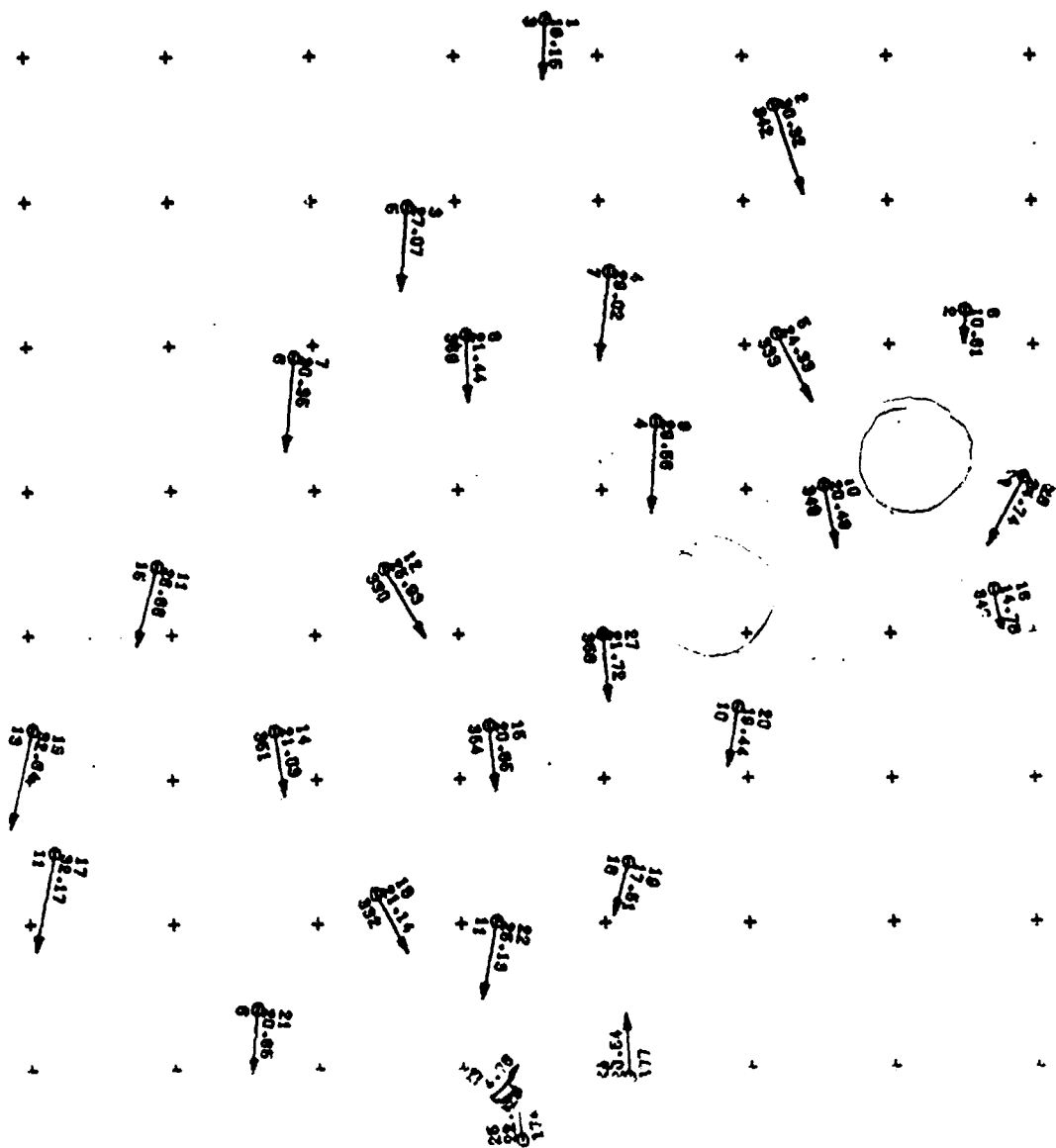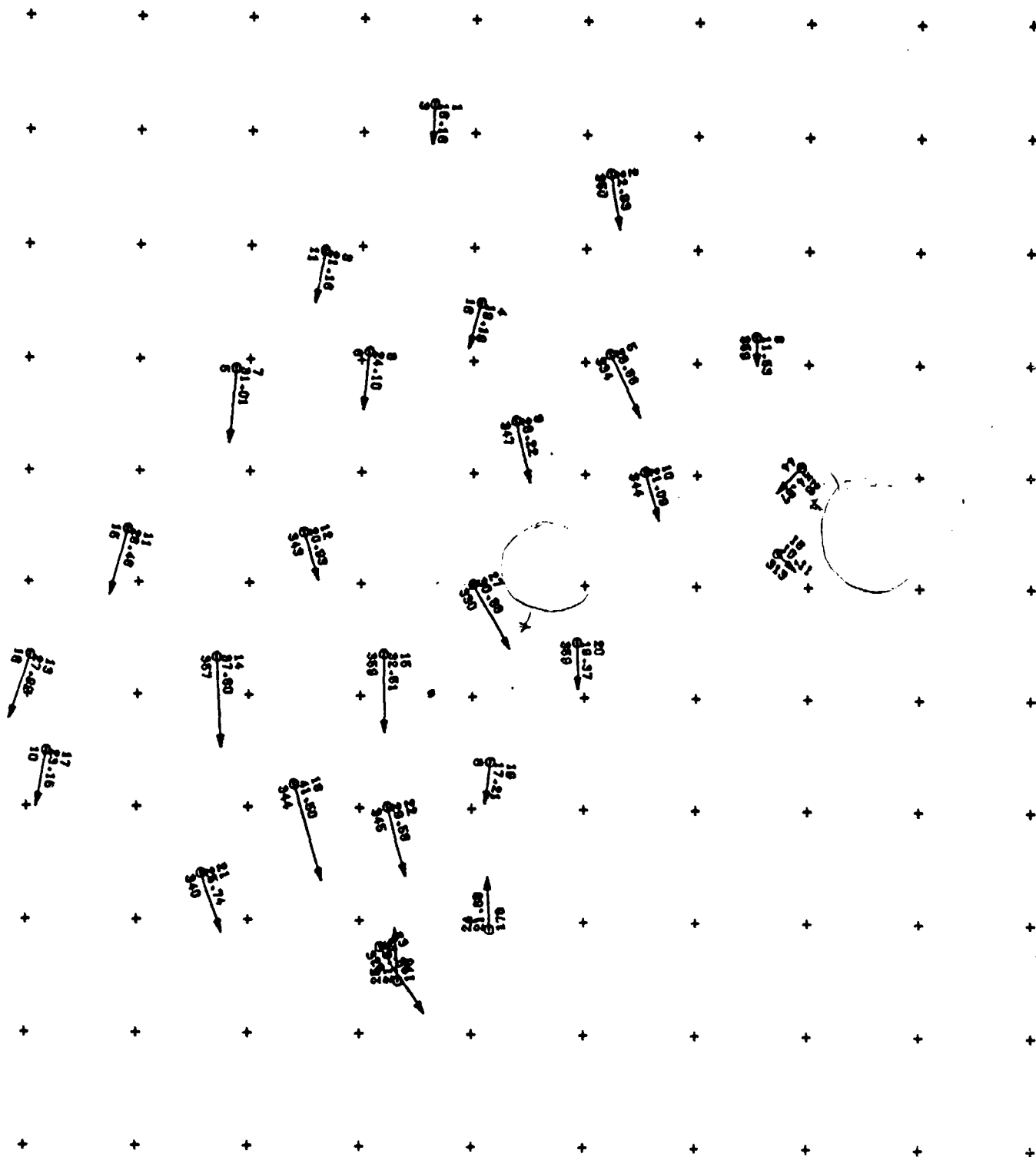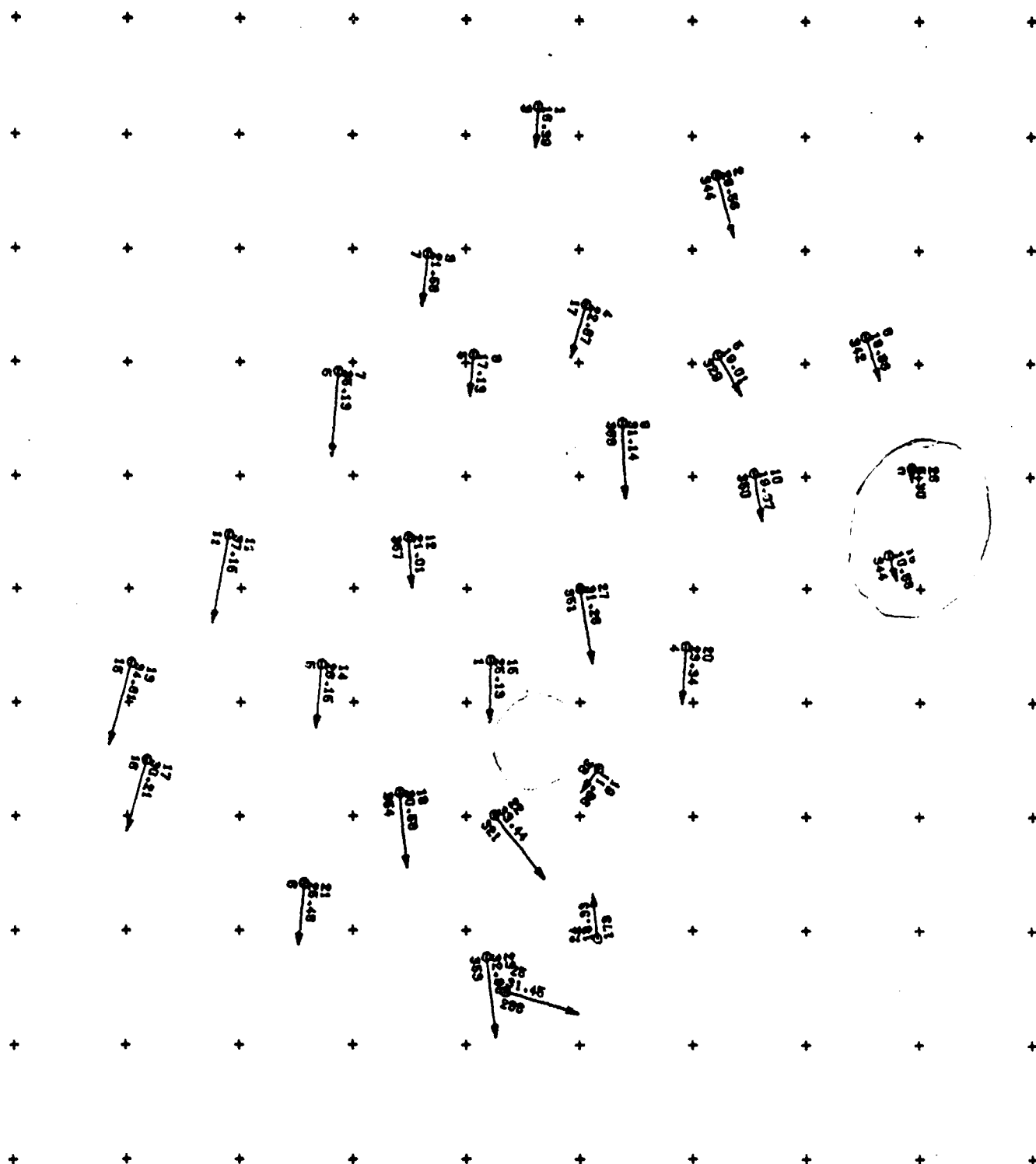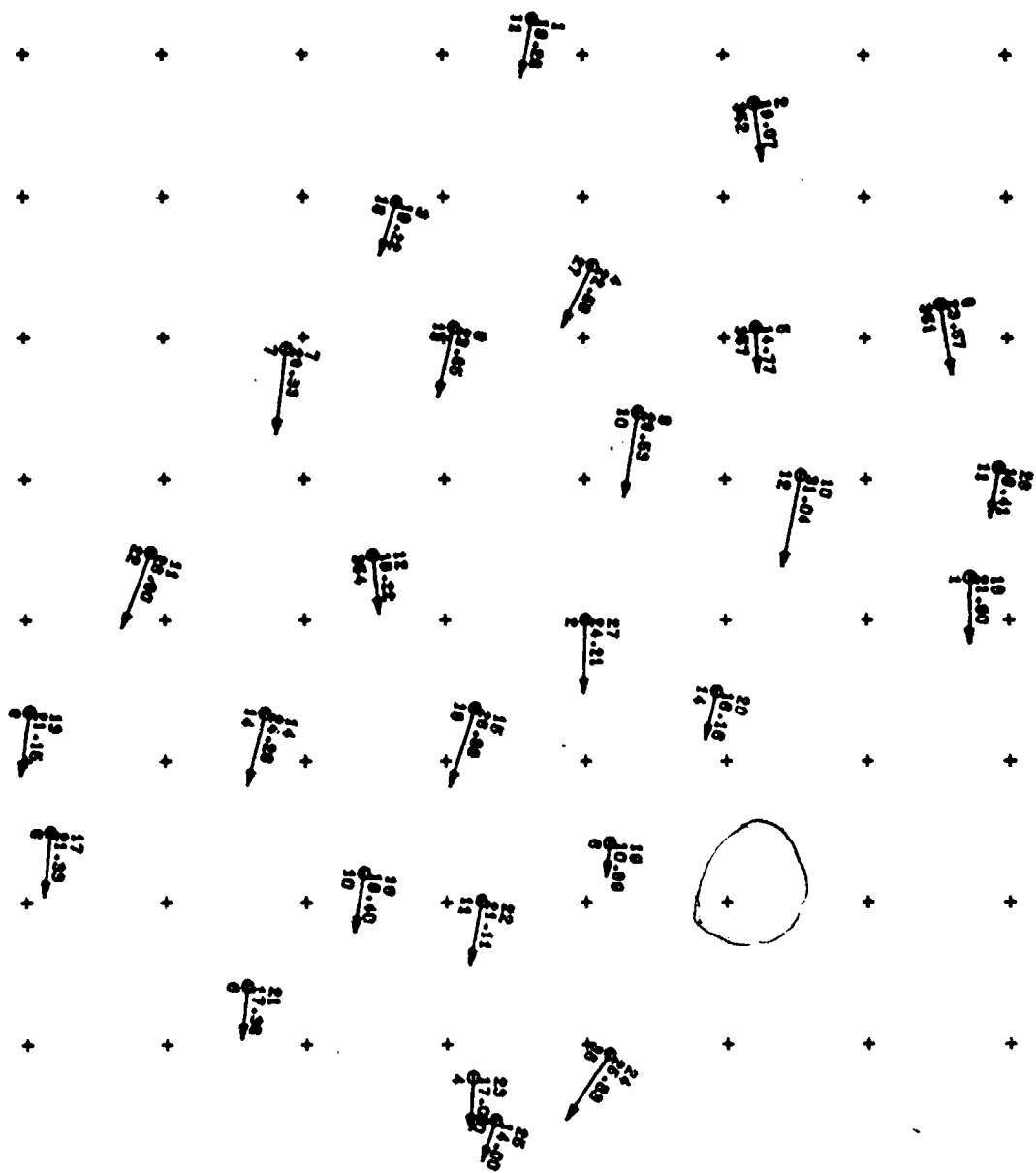

Figure 9ee. Wind speed and direction maps for a front for the SESAME array for
20 minute periods from 3:40 - 10:10 p.m.

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The set of the wind ⌐ ⌐ can help explain the inconsistencies found in application of the win⌐ ⌐ iction methodology to the 3:00 - 10:00 p.m. record on May 2, 1979 shown in Figure 9. The direction of propagation of the meteorological event could not be predicted with confidence and the set of prediction delays were not always consistent with the geographical distance from the reference sites using the methods developed in [20]. Both of theses inconsistencies can be explained based on the analysis of the wind maps.

The meteorological event propagation direction of the incoming storm front is known to be from northwest to southeast from the wind maps. The methodology used to determine meteorological event propagation direction, discussed in Section 3, should indicate that the correlations $P_{ij}(T_{ij})$ in the first five columns should be larger than in the first five rows $P_{ji}(T_{ji})$ given the ordering of sites in Table 1 is in the known propagation direction. Elements corresponding to site 9, 11, 13, 17, 19, and 21 had one or more elements $P_{ij}(T_{ij})$ in the first five rows larger than the elements in the first five columns. These six sites did not experience the first storm that began at 6:30 as shown in the wind maps in Figure 9. Since the long smoothing interval emphasizes the propagation of the large and long duration wind speed increase associated with the storms, the correlation for sites without storms would be small and would not necessarily indicate the propagation direction properly as was observed from the correlation in Table 1. Ignoring correlations from site 9, 11, 13, 17, 19, and 21, the meteorological event propagation direction would be predicted perfectly using the methodology developed.

The prediction delays given in Table 2 are not consistent with geographic distance from reference sites 1-5. Group 1 (6,8,26), Group 2 (10,27,16), Group 6 (22,23,24) and Group 11 appear consistent with geographical distance and the propagation of the part of the first storm that propagates the entire length of the array. Sites (7,9,11) in Group 3 experienced the second storm but did not experience the first storm. The long delay between sites (7,9,11) in Group 3 and the reference sites appear to be an attempt to correlate the first storm at sites 1-5 that first appears at 6:30 and the second storm that first appears at 9:30 in sites 1-5 and propagates toward sites in Group 3. With storms being local in nature and recurrent, it appears to be difficult to track a storm path and correlate the reference group that experiences the same storm as a specific wind turbine cluster. The prediction of the cyclic variation in storms is difficult due to changes in the shape of the large cyclic wind speed variations in storms. Thus, efforts to track storms and to accurately predict the wind speed variation caused by the storm in a particular wind turbine array appears to be nearly impossible in real time with measurements available.

The delays in sites in Group 4 (12,14,15), Group 5 (13,17), Group 7 (19) and Group 9 (21) are small and these sites do not experience the first or second storms. Since the smoothing interval is long and thus emphasizes the effects of the large and long duration wind speed increase associated with the storm, the short duration drop in wind speed for the wind shift is filtered and time shifted. Thus, accurate prediction of the wind shift is

SITES	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27
1	--	.76	.90	.72	.73	.51	.37	.50	.38	.11	.44	.68	.62	.48	.17	.11	.58	.40	.60	.31	.49	.34	.37	.33	.88	.47	.33
2	.76	--	.08	.79	.92	.72	.46	.81	.50	.58	.60	.54	.57	.78	.40	.55	.66	.49	.59	.35	.85	.42	.48	.42	.89	.64	.69
3	.90	.08	--	.66	.81	.53	.39	.62	.46	.34	.52	.50	.55	.69	.29	.32	.60	.44	.45	.35	.66	.35	.39	.35	.86	.46	.47
4	.72	.79	.66	--	.93	.87	.39	.86	.49	.66	.61	.92	.50	.72	.26	.69	.61	.53	.94	.35	.86	.48	.56	.49	.88	.89	.85
5	.73	.92	.81	.93	--	.88	.52	.93	.56	.67	.67	.76	.60	.86	.40	.66	.71	.56	.79	.40	.92	.49	.56	.49	.90	.85	.83
6	.51	.72	.53	.90	.88	--	.54	.96	.56	.84	.67	.89	.60	.76	.50	.88	.71	.56	.90	.40	.86	.50	.57	.50	.69	.97	.94
7	.49	.33	.40	.39	.33	.33	--	.22	.59	.59	.01	.46	.44	.18	.72	.57	.39	.80	.41	.77	.21	.86	.93	.85	.69	.39	.38
8	.52	.81	.62	.88	.93	.96	.54	--	.47	.84	.57	.81	.71	.88	.62	.86	.81	.58	.85	.77	.21	.86	.93	.85	.56	.73	.04
9	.36	.37	.34	.29	.28	.14	.45	.16	--	.27	.88	.25	.44	.42	.49	.27	.64	.87	.22	.43	.94	.39	.75	.78	.72	.24	.14
10	.66	.41	.53	.68	.62	.83	.44	.82	.47	--	.57	.79	.76	.65	.74	.98	.80	.47	.82	.67	.25	.41	.47	.42	.42	.84	.93
11	.38	.27	.30	.32	.26	.22	.74	.18	.89	.39	--	.34	.39	.20	.50	.42	.65	.90	.31	.61	.79	.84	.86	.82	.36	.29	.24
12	.68	.54	.50	.92	.73	.71	.47	.63	.39	.53	.49	--	.62	.45	.24	.56	.50	.47	.95	.31	.65	.44	.50	.45	.77	.76	.74
13	.51	.39	.51	.34	.32	.03	.32	.04	.44	.11	.40	.39	--	.26	.25	.13	.88	.38	.18	.21	.21	.42	.35	.39	.56	.08	.04
14	.49	.78	.62	.75	.86	.75	.45	.88	.55	.73	.66	.61	.76	--	.67	.71	.84	.52	.67	.43	.90	.39	.48	.41	.68	.73	.82
15	.61	.46	.57	.34	.38	.52	.25	.61	.37	.83	.44	.52	.75	.66	--	.79	.76	.37	.52	.80	.63	.61	.64	.69	.58	.50	.70
16	.65	.42	.52	.72	.64	.87	.44	.83	.47	.98	.57	.83	.72	.65	.70	--	.78	.48	.84	.63	.78	.41	.47	.41	.46	.88	.94
17	.53	.43	.60	.20	.30	.02	.36	.01	.64	.04	.67	.15	.88	.28	.18	.05	--	.56	.03	.28	.17	.38	.36	.38	.50	.03	.02
18	.40	.36	.31	.35	.31	.22	.49	.22	.81	.34	.81	.34	.29	.30	.49	.37	.32	--	.32	.56	.25	.93	.87	.91	.40	.32	.23
19	.60	.59	.45	.94	.78	.85	.49	.76	.42	.70	.52	.96	.62	.54	.24	.73	.55	.49	--	.32	.74	.46	.52	.47	.75	.87	.85
20	.50	.43	.52	.26	.33	.21	.16	.23	.37	.67	.41	.31	.61	.27	.74	.62	.67	.29	.32	--	.30	.39	.47	.56	.40	.27	.47
21	.52	.82	.57	.86	.90	.05	.50	.92	.54	.82	.66	.72	.72	.87	.59	.80	.82	.56	.79	.42	--	.45	.53	.46	.74	.82	.91
22	.49	.43	.41	.39	.35	.24	.26	.21	.63	.43	.56	.37	.40	.29	.63	.42	.34	.90	.33	.61	.26	--	.93	.95	.48	.35	.22
23	.45	.36	.37	.39	.34	.28	.17	.23	.47	.46	.39	.41	.37	.23	.69	.47	.30	.77	.36	.66	.24	.92	--	.93	.46	.35	.27
24	.47	.44	.42	.38	.37	.21	.07	.22	.42	.40	.30	.35	.42	.31	.69	.38	.36	.69	.31	.62	.29	.88	.91	--	.49	.31	.19
25	.88	.89	.86	.08	.90	.69	.45	.72	.43	.35	.52	.77	.58	.68	.22	.35	.50	.44	.75	.31	.74	.41	.47	.42	--	.65	.58
26	.50	.64	.46	.91	.85	.97	.53	.93	.53	.04	.64	.92	.50	.73	.48	.08	.68	.54	.92	.37	.83	.49	.56	.49	.67	--	.93
27	.58	.59	.49	.05	.79	.90	.50	.09	.53	.93	.65	.86	.73	.75	.59	.93	.81	.55	.89	.50	.89	.47	.54	.47	.58	.93	--

Table 1. Peak correlation matrix $P_{ij}(T_{ij})$ for 2 hour filtered data from 3:00 – 10:00 p.m. on May 2, 1979.

Group	Site	Individual Site Delays (Minutes)					Group/Site Delay T_i	Group/Group Delay $T(i)$
		T_{i1}	T_{i2}	T_{i3}	T_{i4}	T_{i5}		
1	6	—	—	—	—	—	—	2
1	8	5	—	8	—	—	—	2
1	26	—	—	—	—	—	—	2
2	10	54	40	58	—	23	35	30
2	27	34	30	41	—	20	25	30
2	16	47	41	51	—	17	31	30
3	7	208	205	204	189	198	201	198
3	9	231	221	21	207	215	179	198
3	11	227	216	222	200	210	215	198
4	12	—	16	—	13	24	11	55
4	14	29	—	18	—	2	10	55
4	15	338	24	48	301	12	145	55
5	13	37	200	19	166	191	123	118
5	17	22	198	—	172	188	116	118
6	22	275	275	270	259	266	269	279
6	23	290	288	289	271	281	284	279
6	24	290	289	288	276	287	286	279
7	19	—	22	—	—	20	9	9
8	20	362	351	353	318	345	346	346
9	21	30	12	26	—	10	16	16
10	25	—	—	—	—	—	—	1
11	18	259	243	249	224	237	242	242

Table 2. Delays associated with propagation of the storm cell for data from 3:00-10:00 p.m. on May 2, 1979.

difficult using the data with this long smoothing interval. The results
from Table 2 indicate that the delays for these sites in groups 4, 5, 7, and
9 are short compared to the propagation speed of the wind shift (40 mph) and
their geographical distance from sites 1-5.

The errors and delays for the individual site, group/site, and
group/group model are given in Table 3. Note that the error for sites in
Groups 4, 5, 7, and 9 that had no storm are small. The errors for site in
group 6 and 11, that contained the storm that appeared in the reference
group were not large. Sites in group 1 and 2 contained several storms and
thus the errors were large since only the propagation of the one storm was
predicted.

The errors for the individual site model was smallest since the
informaton in each of the individual site records can be used for
prediction. The errors for the group/site model are generally considerably
larger than for the individual site model since only one averaged record is
utilized with a single averaged delay. Use of several reference groups can
greatly improve the performance of the group/site model. The group/group
model estimates the average wind speed at a group of measurement sites in a
wind turbine cluster rather than the individual sites in that cluster. This
group/group model that estimates the average wind speed in the wind turbine
cluster based on average wind speed record of a reference group and an
average delay is by far the worst model. It not only disregards the very
significant wind speed average, rms and cyclic variations in each record at
sites in the wind turbine cluster but also ignores this information at
individual sites in the reference group. Methods of utilizing the
individual predicted wind speed records in a wind turbine cluster to
accurately simulate wind power out of the wind turbines in the array is
discussed in Section 6 of this report.

4.3 THE EFFECTS OF FILTERING ON WIND SPEED PREDICTION

The long smoothing interval used to determine the meteorological event
propagation direction, reference groups, and prediction groups for the
meteorological event should not be used to produce the actual wind speed
prediction record. Comparison of the actual and predicted wind speed
records in Figure 10 with a 2 hour smoothing interval and those in Figure 11
and 12 with 10 minute and 2 minute filtering intervals shows significant
differences. It is clear that filtering very significantly modifies the
actual wind record but has substantially less effect on the predicted wind
records that begin at 270-290 minutes in Figure 10-12. Note that the peak
on the actual site 22 record at t = 310 minutes (8:10 p.m.) was reduced from
64 to less than 50 if the smoothing interval is 10 minutes rather than 2
minutes. The higher frequency fluctuations were filtered out of both the
predicted and actual record by the longer smoothing interval. The magnitude
of the trend change in predicted speed (slope of the average wind speed
before t = 300 and slope of the average wind speed after t = 300) on the
predicted wind speed records at site 22 experienced little change with the
longer filtering interval. Similar conclusions are reached in the analysis
of sites 23, 24, and 25 in Figures 11 and 12 for 10 and 2 minute smoothing
intervals.

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Group	Site No.	No. Averaging Maximum Site Delay	Error (mph)	Reference Group Averaging Group/Site Delay (minutes)	Error (mph)	Reference and Prediction Group Averaging Group/Group Delay (minutes)	Error (mph)
1	6	1	1.51	1	2.69	2	2.18
1	8	3	0.49	1	1.28	2	2.18
1	26	1	1.22	1	2.84	2	2.18
2	10	58	1.00	35	3.41	30	2.61
2	27	41	0.67	25	1.89	30	2.61
2	16	51	1.06	31	2.89	30	2.61
3	7	208	0.51	201	0.60	198	0.62
3	9	231	0.23	179	1.37	198	0.62
3	11	227	0.28	215	0.54	198	0.62
4	12	24	0.43	11	2.78	55	1.07
4	14	29	0.64	10	1.41	55	1.07
4	15	338	0.11	145	0.52	55	1.07
5	13	200	0.31	123	1.97	119	1.98
5	17	198	0.66	116	2.96	119	1.98
6	22	275	0.36	269	2.08	279	0.42
6	23	290	0.15	284	0.37	279	0.42
6	24	290	0.33	286	0.85	279	0.42
7	19	22	0.75	9	2.24	9	2.24
8	20	363	0.14	346	0.39	346	0.39
9	21	30	0.47	16	0.37	16	0.37
10	25	1	0.68	1	1.72	1	1.72
11	18	259	0.36	242	0.85	242	0.85

Table 3. Errors and delays for individual site, group/site, and group/group models
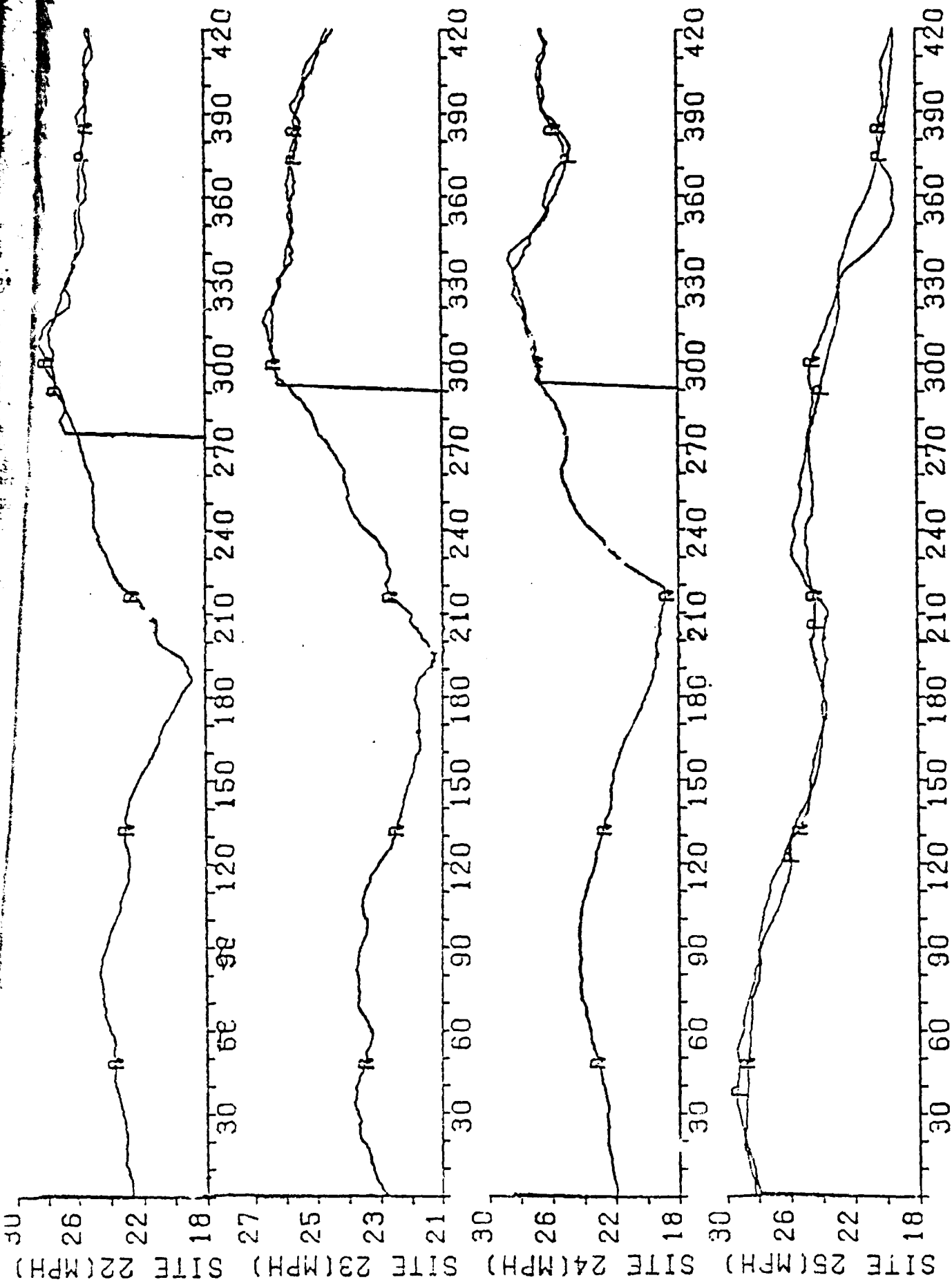
Figure 10   Actual and predicted wind speed records for 3:00 - 10:00 p.m. May 2, 1979 data using 2 hour moving average filtered records and sites 1-5 as reference.

FIGURE 11. ACTUAL AND PREDICTED WIND SPEED RECORDS FOR 3:00 TO 10:00 P.M. ON MAY 29, 1975 DATA USING 10 MINUTE MOVING AVERAGE RECORDS AND SITES 1-5 AS REFERENCE.

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Figure 12. Actual and predicted wind speed records for 3:00 – 10:00 p.m. data on
May 2, 1979 using 2 minute moving average filtered records and Sites 1-5
as references.

Comparison of the actual wind speed records in sites 22-25 are no further than 15 miles apart shows radically different shaped wind speed cyclic variations. Either the cyclic wind speeds variation within a storm must be radically different at different points within the storm; or the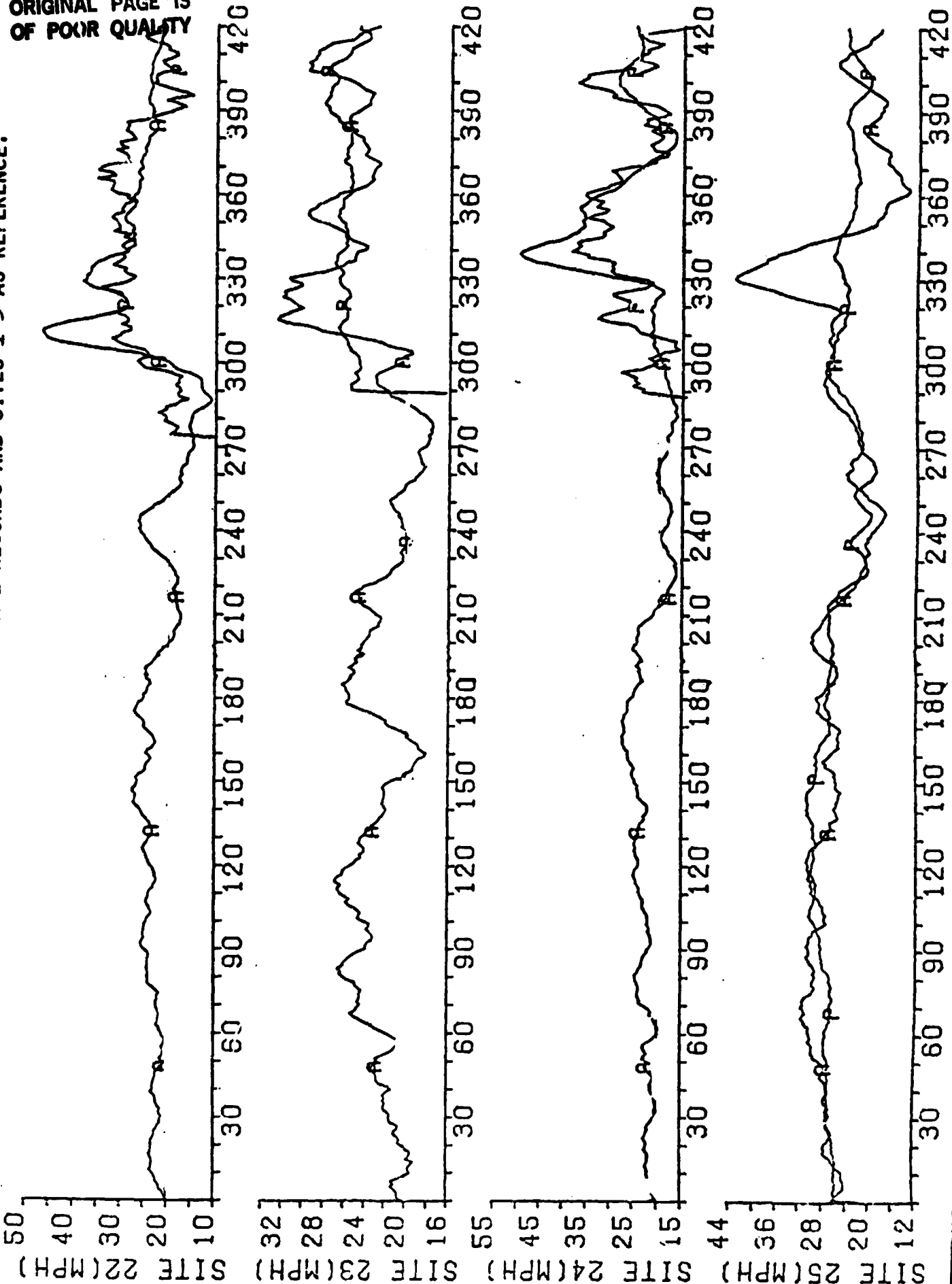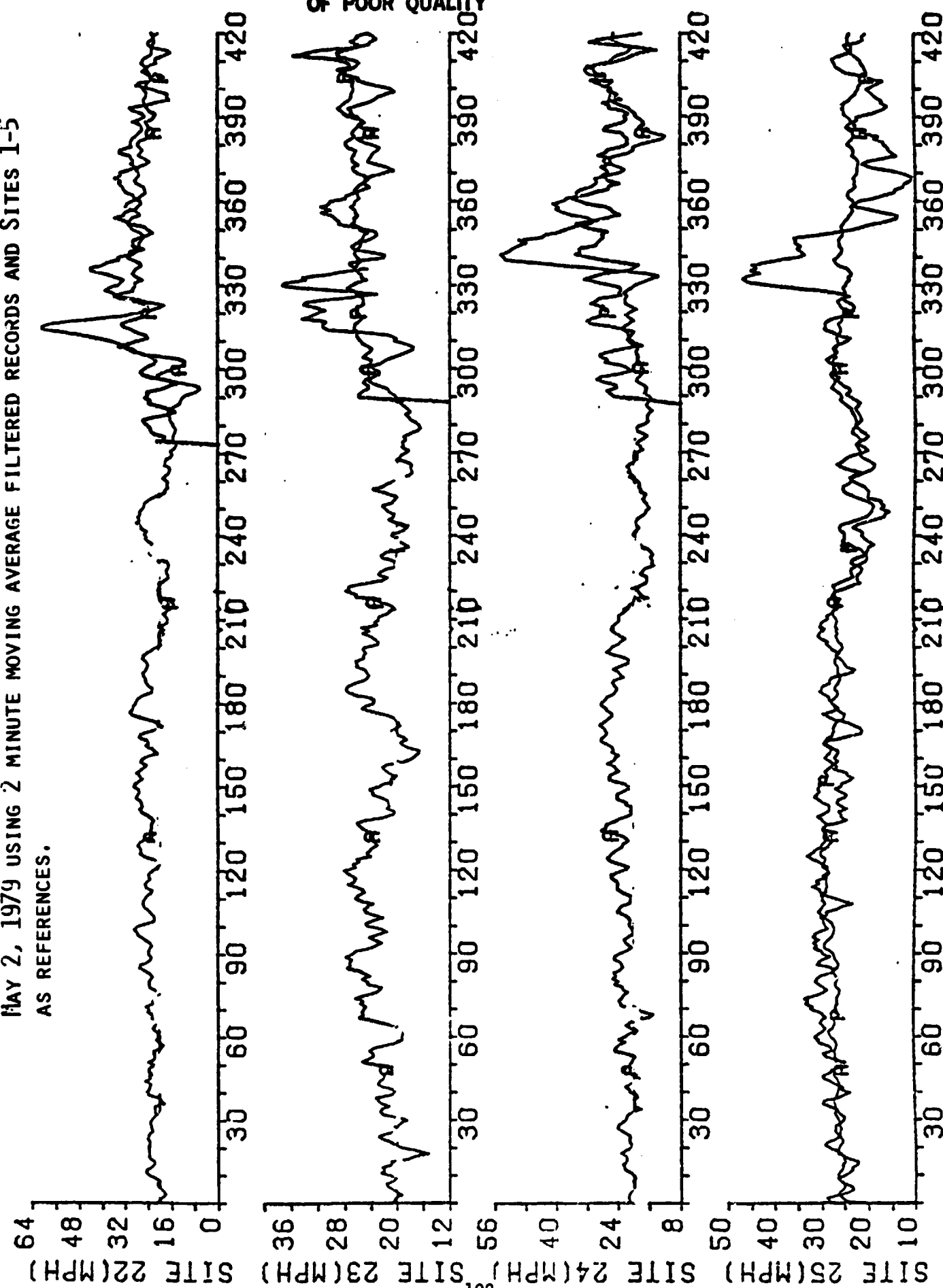 cyclic variations must change radically with time; or both. Thus, it appears impossible to predict these very large cyclic storm induced variations at any site because (1) the prediction methodology appears to filter them out (and only captures the average wind speed increase associated with the storm), (2) the large cyclic wind speeds at each site are so different from other sites close to it, and (3) the cyclic variations at the prediction sites are also different than at the reference sites.

The 2 hour filtering interval totally distorts the actual and the predicted wind speed records. The large cyclic variations in the actual records completely disappear and the actual and predicted records appear to be nearly identical. The relatively short storm induced pulse at site 25 is completely eliminated, which explains why the delay chosen is 1 minute rather than 270-290 minutes. The longer storm induced variations on sites 22-24 are indicated as a 2 hour ramp increase in wind speed starting at t = 180 (6:00 p.m.) and reaching a maximum between 300 (8:00 p.m.) and 330 (8:30 p.m.) when the actual sharp peak in wind speeds occur. The wind speed at maximum (near t = 180) is larger and the average wind speed during the storm (t > 300) is smaller using the 2 hour filtering.

The errors between the actual and predicted wind for 2 minute, 10 minute, and 2 hour smoothed data are given in Table 4. Note that the errors increase dramatically as the smoothing interval is shortened and the size of the error is small at sites that have no storm (13,17,19,21,12,14,15) in the 2 minute filtered data.

4.4 THE EFFECTS OF USING DIFFERENT REFERENCE GROUPS

The prediction of wind speed at sites 22-24 captured the propagation of the storm observed in reference group 5. The storm induced cyclic variation changed so much over time that the prediction errors were quite large for the 2 minute data despite the fact that the storm propagation had been predicted.

A set of three references (10,16,27) in Group 3 were used to predict the wind speed at sites (22-4) to determine if utilizing a reference group closer to the prediction group sites 22-24 would decrease the prediction errors. The delays for prediction of sites 22-24 utilizing references (10,16,27) were determined based on a 2 minute filtering interval rather than the 2 hour filtering interval used to determine the delays for reference group 1-5 given in Table 2. The delays for site 10, 16, and 27 to each to the prediction sites 22-24 are given in Table 5. The maximum delays to site 22, 23, 24 is 275, 280, and 290, respectively, using references 1-5 but the average delay for sites 22-24 is 181, 253, and 221, respectively, using references 10, 16, 27. The delays decrease from 16-33% where the geographical distance between sites 22-24 to the reference sites has decreased approximately 40%.

TABLE 4. TABLE OF WIND SPEED PREDICTION ERROR FOR 2 MINUTE, 10 MINUTE, AND 2 HOUR DATA OF 05/02/79 (3 - 10 P.M.)

SITE	2 MINUTE FILTERED ERROR (MPH)	10 MINUTE FILTERED ERROR (MPH)	2 HOUR FILTERED ERROR (MPH)
6	5.20	4.47	1.51
7	5.82	4.71	0.51
8	2.91	1.91	0.49
9	5.52	3.93	0.23
10	4.65	3.29	1.00
11	5.82	4.02	0.28
12	4.83	3.74	0.48
13	4.28	2.89	0.31
14	4.78	3.69	0.64
15	3.49	1.89	0.11
16	4.64	3.83	1.06
17	8.53	7.24	0.66
18	7.98	6.11	0.36
19	4.81	3.84	0.75
20	2.80	1.69	0.14
21	4.02	3.01	0.47
22	8.12	5.78	0.36
23	3.97	2.96	0.15
24	8.59	5.80	0.33
25	4.74	4.02	0.68
26	5.02	4.11	1.22
27	4.24	3.51	0.67

Prediction Sites	Maximum Delay From Sites 1-5 in Minutes 2 Hour Filtered	Delay in Minutes		
		Site 10	Site 16	Site 27
		(2 Minute Filtered Data)		
22	275	1	168	195
23	290	255	244	262
24	290	190	237	27

TABLE 5 COMPARISON OF DELAYS USING SITES 10, 16, 27 AND SITES 1-5 AS REFERENCES.

Prediction Sites	Reference 1-5		Reference 10, 16, 27	
	Error (mph) 10 Minute Filtered	Error (mph) 2 Minute Filtered	Error (mph) 10 Minute Filtered	Error (mph) 2 Minute Filtered
22	5.787	8.123	4.494	6.271
23	2.966	3.978	2.596	4.011
24	5.302	8.599	5.573	6.368

TABLE 6 COMPARISON OF WIND SPEED PREDICTION ERRORS USING SITES 10, 16, 27 AND SITES 1-5 AS REFERENCES.

The errors between the actual and predicted wind speed records are given in Table 6 and decrease 0-25% using references (10,16,27) rather than (1-5). The errors are for the individual site predictive model.

Sites (7,9,11) are also used as references. These sites experience the second storm but not the first. The delays given in Table 7 are computed with the 2 minute smoothed data and are considerably smaller than utilizing references (10,16,27) or (1-5). These delays appear to represent the delay associated with the propagation speed on the wind shift (40 mph) and the distance (40 miles) between references (7,9,11) and prediction sites 22-24. The delay from reference 7 is longer than 9, 11, and is approximately 10-15 miles further from the prediction sites. Site 24 is farther from the references (7,9,11) than sites 22 and 23 and again has longer delays. The use of a reference without the storm and a short 2 minute smoothing interval clearly and accurately determines delays associated with the wind shift propagation. The errors between the actual and predicted wind speed at sites 22-24 is 20-40% less than using references (7,9,11) rather than references (1-5) as shown in Table 8 for both the 2 and 10 minute filtered data. Figures 13 and 14 plot the actual and predicted wind speed record on sites 22-24 for reference (10,16,27) and (7,9,11) respectively. Note that the delays are much shorter using reference (7,9,11) and that the errors are very small except during the storm. A very surprising result is that the rise in wind speed and the cyclic variations in wind speed associated with the storm appear to be more accurately predicted on sites 22 and 23 using sites (7,9,11) that did not contain this first storm. The error during the storm is still quite large and the cyclic variations in the actual record are never truly predicted at any of the sites.

These results further confirm the conclusion that one should not attempt to predict storms because

(1) utilizing references without the same storm and a short filtering interval captures wind shift propagation and produced substantially more accurate predicted wind speed records before, during, and after the storm;

(2) the cyclic variation in the storm either is quite different at different points in the storm or changes so radically over time that attempting to accurately predict the storm induced cyclic variation is impossible.

Prediction Sites	Maximum Delay From Minutes 2 Hour Filtered	Delay in Minutes Site 7	Site 9	Site 11
		2 Minute Filtered Data		
22	275	78	33	32
23	295	86	43	48
24	290	105	67	63.

TABLE 7   COMPARISON OF DELAY USING SITES 7, 9, 11 AND SITES 1-5 AS REFERENCES.

Prediction Site	Reference 1-5		Reference 7, 9, 11	
	Error (mph) 10 Minute Filtered	Error (mph) 2 Minute Filtered	Error (mph) 10 Minute Filtered	Error (mph) 2 Minute Filtered
22	5.737	8.123	3.732	5.463
23	2.966	3.973	2.449	3.230
24	5.802	8.599	4.885	5.637

TABLE 8   COMPARISON OF WIND SPEED PREDICTION ERROR USING SITES 7, 9, 11 AND SITES 1-5 AS REFERENCES.

FIGURE 13. COMPARISON OF ACTUAL AND PREDICTED WIND SPEED FOR 3:00 - 10:00 P.M. USING 2 MINUTE MOVING AVERAGE FILTERED RECORDS AND SITES 10, 16, AND 26 AS REFERENCES.
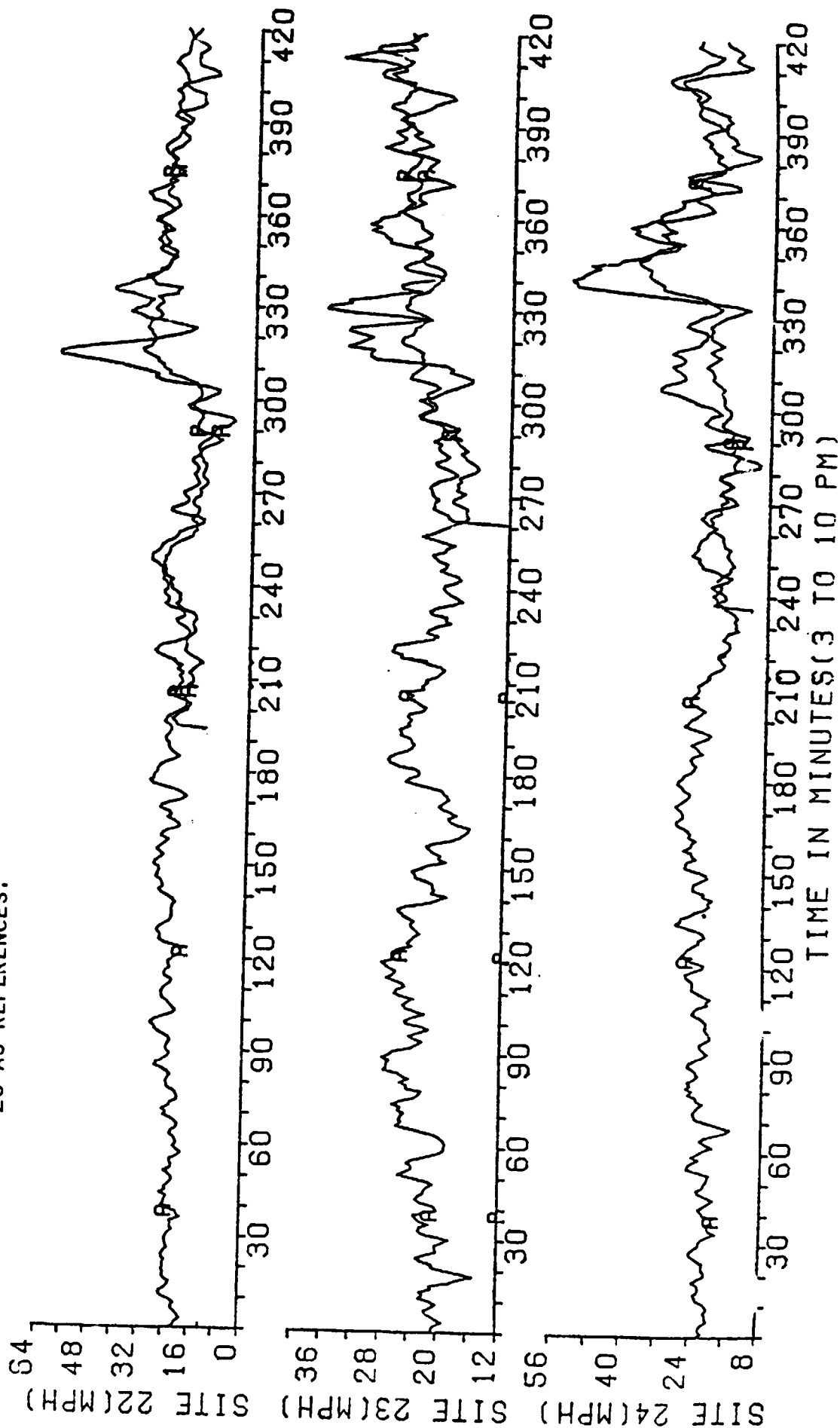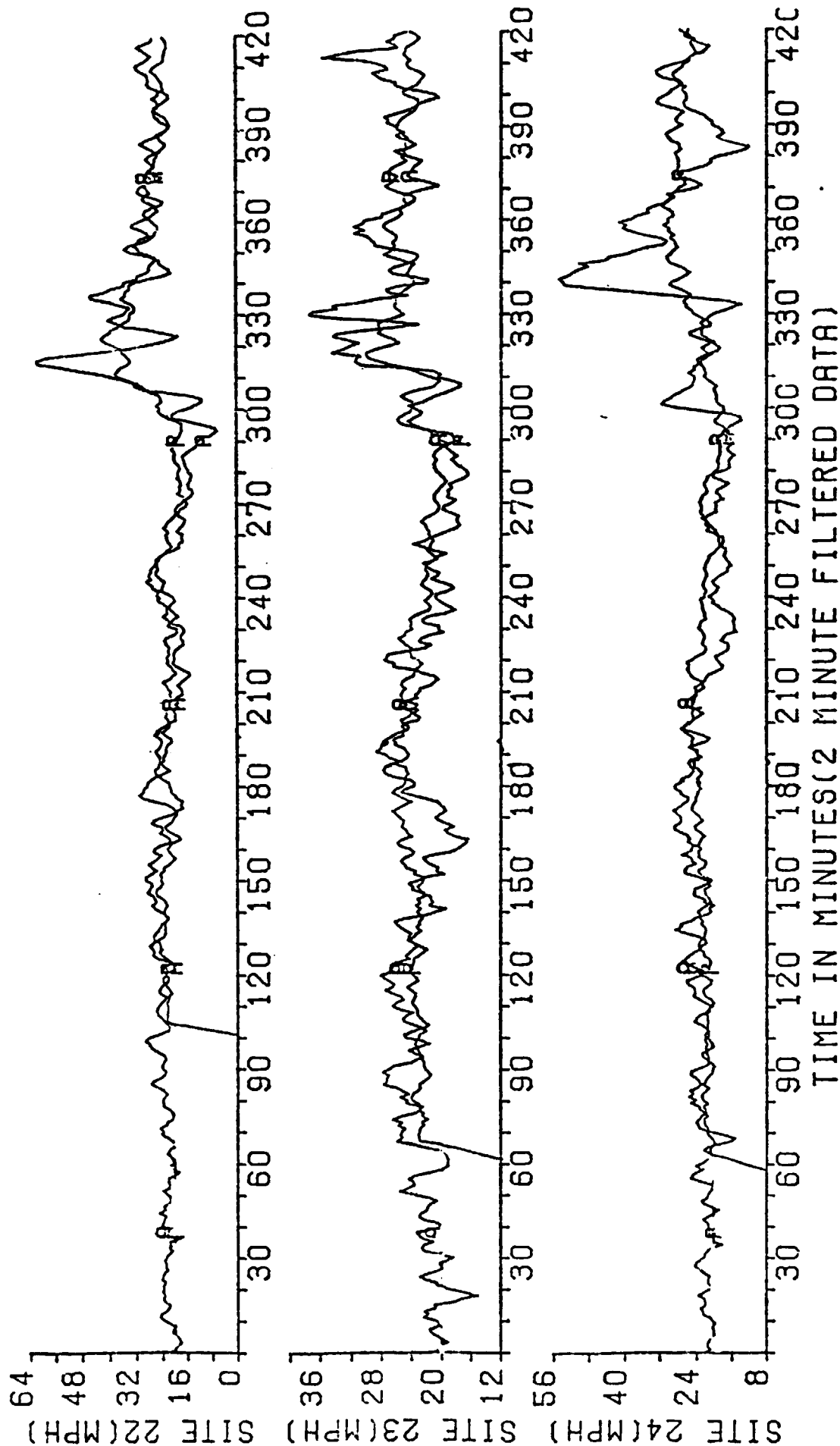
FIGURE 14. COMPARISON OF ACTUAL AND PREDICTED WIND SPEED FOR 3:00 – 10:00 P.M. USING 2 MINUTE MOVING AVERAGE FILTERED RECORDS AND SITES 7, 9, AND 11 AS REFERENCE.

SECTION 5

5.1 WIND POWER SIMULATION AND PREDICTION

Smoothing of wind speed records before simulation of power out of an individual wind turbine or wind turbine array is shown to cause serious distortion of the wind turbine or array power in Section 5.2. Smoothing of the wind speed records utilized to produce the predicted wind speed record and therefore the resultant simulated array power is shown to cause significantly less distortion from results presented in Section 5.3. The predicted wind speed and the predicted array power record that is produced from it are effected by an inherent spatial filtering caused by the use of several reference sites at different locations. Thus, predicted wind array power is not effected by the smoothing of the reference wind speed records since the spatial filtering has performed the smoothing. Distortion caused by the spatial filtering inherent in the wind speed prediction process is shown in Section 5.4 to cause significant wind array power prediction error, when the smoothing is performed on either the reference wind speed records used to produce the predicted wind speed or the actual wind speed record. The effects of utilizing two predicted wind speed records in the wind turbine cluster to simulate the wind power variation out of that wind turbine array is presented in Section 5.5.

5.2 EFFECTS OF FILTERING ON THE SIMULATION OF WIND POWER VARIATION

The simulation of power out of a MOD-2 wind turbine given a record of wind speed utilizes a computer program developed in our earlier research [20]. The simulation program utilizes the nonlinear algebraic power versus wind speed curve. The logic for high speed shutdown and startup and low speed shutdown and startup is included. The program can also simulate the power out of an array of MOD-2's given the siting configuration and the propagation speed of the meteorological event. The siting configuration is specified in terms of the abscissa and ordinate position in miles from the wind turbine that is at the boundary of the array in the direction of propagation. The square array simulated in this section is composed of 81 sited in a matrix with separation of 1 mile in the abscissa and ordinate direction. The speed of propagation of the meteorological event is taken as 30 mph, which is quite slow compared to the propagation speeds for meteorological events observed in our research on the SESAME array. A larger meteorological event propagation velocity increases the rate of change of power out of an individual wind turbine and out of an array of wind turbines.

The effects of filtering the wind speed record on site 14 on the magnitude of the power out of a single wind turbine is shown in Figure 15. The wind speed is near rated velocity and thus the wind power is repeatedly in and out of saturation. The magnitude of the variation can be 1.6 megawatts and the periods of these oscillations range from 2 minutes to 10 minutes in the unfiltered case in Figure 15a. The 2 minute and 5 minute smoothing greatly reduce the magnitude of these variations so that the peak variation is 1.2 MW and 0.6 MW, respectively. The period of the oscillations increase also as the higher frequency components of these oscillations are filtered out.

FIGURE 15A. ACTUAL POWER FROM A SINGLE WIND TURBINE AT SITE 14 USING AN UNFILTERED WIND RECORD.
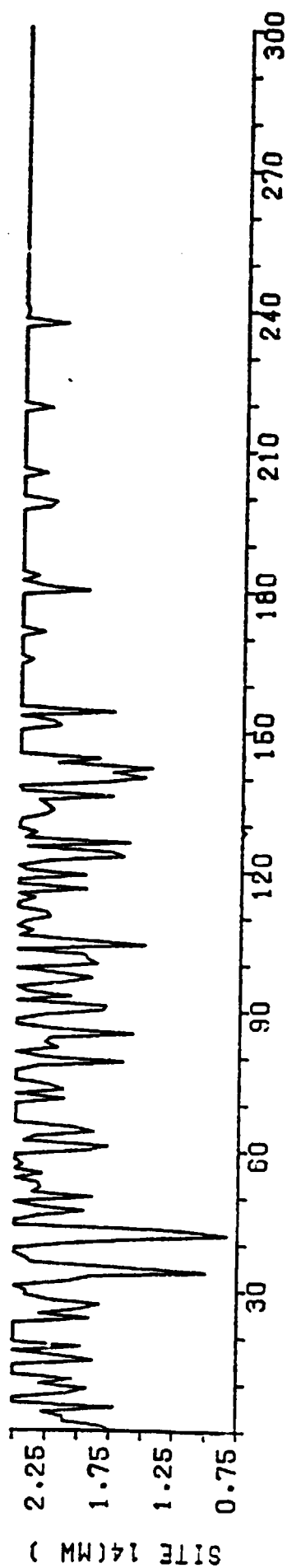
111

FIGURE 15B. ACTUAL POWER FROM A SINGLE WIND TURBINE AT SITE 14 USING A 2 MINUTE MOVING AVERAGE FILTERED SPEED RECORD.
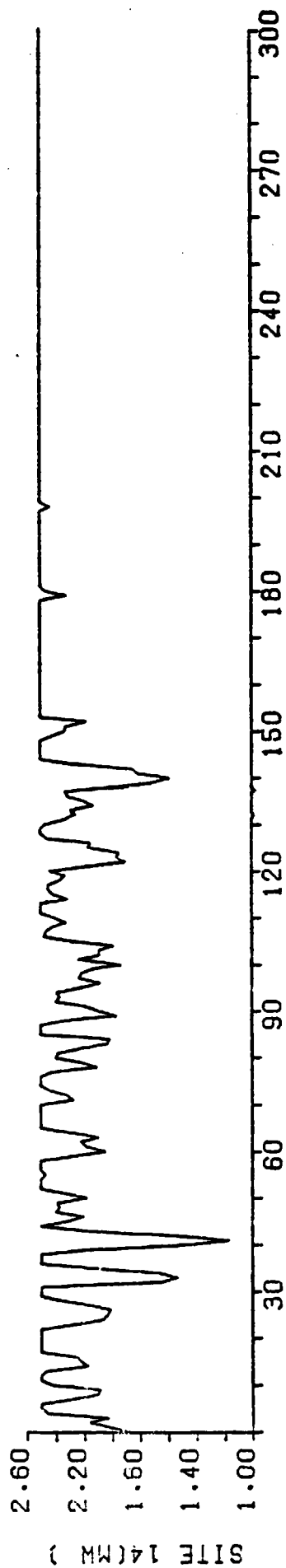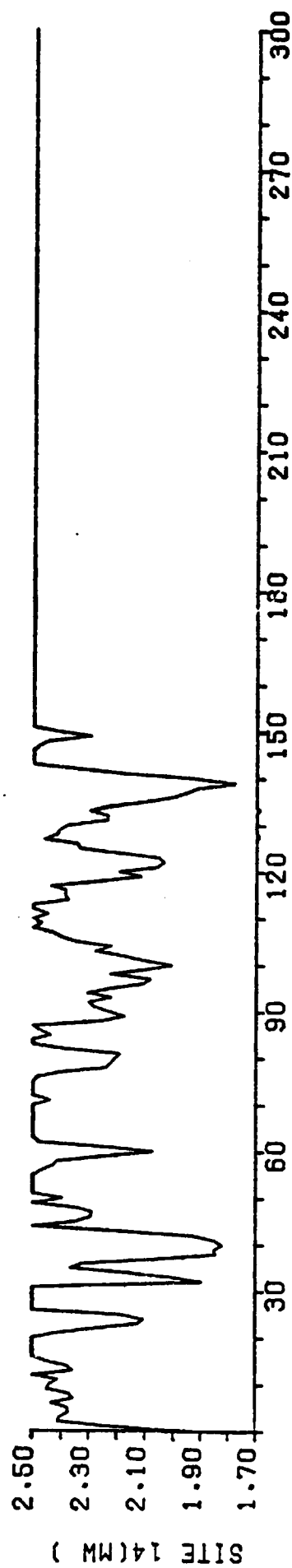
Figure 15c. Actual power from a single wind turbine at Site 14 using a 5 minute moving average filtered record.

The power out of individual wind turbines at site 14, 17, and 18 was
simulated to indicate the variation in wind power for three wind turbines
that are within 20 miles of each other as shown in Figure 16. The power out
of the three wind turbines is given in Figure 17 utilizing wind records from
1:00 - 6:00 p.m. on May 2, 1979 with a 10 minute smoothing interval. The
1.6 MW maximum wind power variation on site 14 in the unfiltered record is
now only 0.5 MW and the period is now greater than 10 minutes. This 10
minute smoothed power output record is not at all similar to that in Figure
15a with no smoothing effects on the magnitude, frequency, or shape of the
variation. Filtering the wind speed record before simulation of power
totally destroys the power variations out of an individual wind turbine for
a front.

The wind speed increase and concommitant wind power increase for the
arrival of the front can be observed in sites 17 and 18 for the power
simulated utilizing the 10 minute smoothed records. The magnitude of the
power output is very different because the average and rate of change of
wind speed is quite different on these three sites. Site 17 eventually
nears and exceeds rated wind speed on a MOD-2 at t = 230 minutes but site 18
wind speed and power never reach rated velocity at t = 300 minutes. The
shape of the wind power variation at sites 17 and 18 are very different even
though the majority of the variation has been filtered out with the 10
minute smoothing interval.

Table 9 shows the mean and rms errors between the filtered and
unfiltered individual wind turbine power output. Note as the smoothing
interval increases from 5 to 30 the mean and rms error in power changes
relatively little for site 14 but shows larger changes for site 17. The m +
3 error is .85 MW for site 14 and 1.35 MW for site 17 with the 5 minute
smoothing interval. This error is very large compared to the 2.5 MW
capacity of the MOD-2 wind turbine.

The power output of the 81 wind turbine array at site 14, 17, and 18 is
given in Figure 18. The 10 minute smoothed individual wind turbine power
record is multiplied by the number of wind turbines in an echelon and
delayed by

$$T_i = \frac{d_i}{V_o}$$

d_i - distance of echelon i from the first wind turbine in the array in the
        direction that the meteorological event is propagating

V_o - speed of propagation of the meteorological event

to produce the power out of the ith echelon of wind turbines. The power out
of the array is the sum of the power out of all echelons. The power out of
the 81 wind turbine array is sites 14, 17, and 18 shown in Figure 18 is a
smoothed version of that in Figure 16 for the individual wind turbine. The
array simulation procedure is a spatial filtering process and thus the
maximum percentage change in power variation is only 10% on the site 14 wind

114
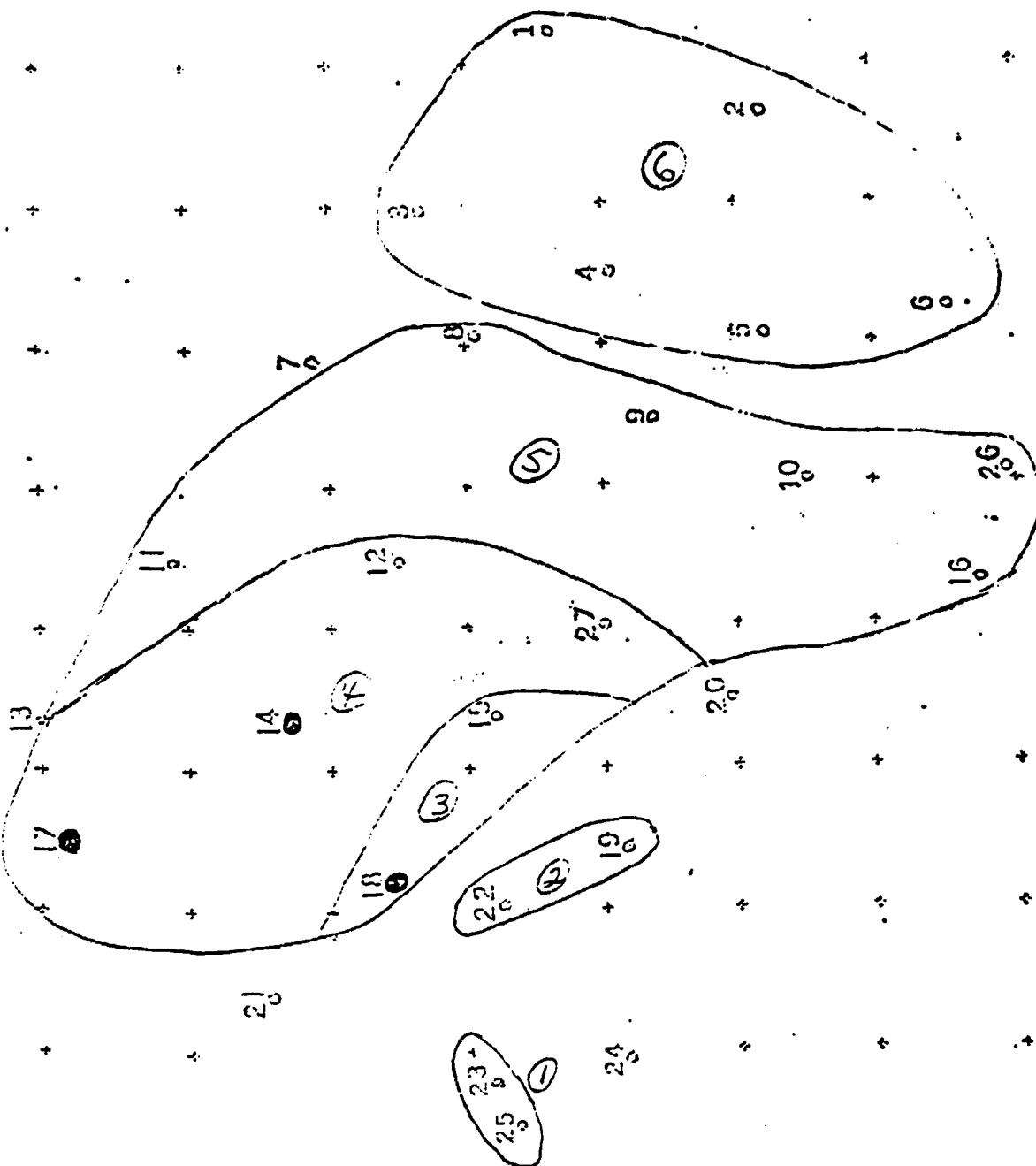
Figure 16. Map of the locations of wind speed measurement sites in the SESAME array.

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FIGURE 17. ACTUAL WIND POWER FROM SINGLE WIND TURBINES AT SITE 14, 17, AND 18 USING 10 MINUTE MOVING AVERAGE FILTERED DATA.

116
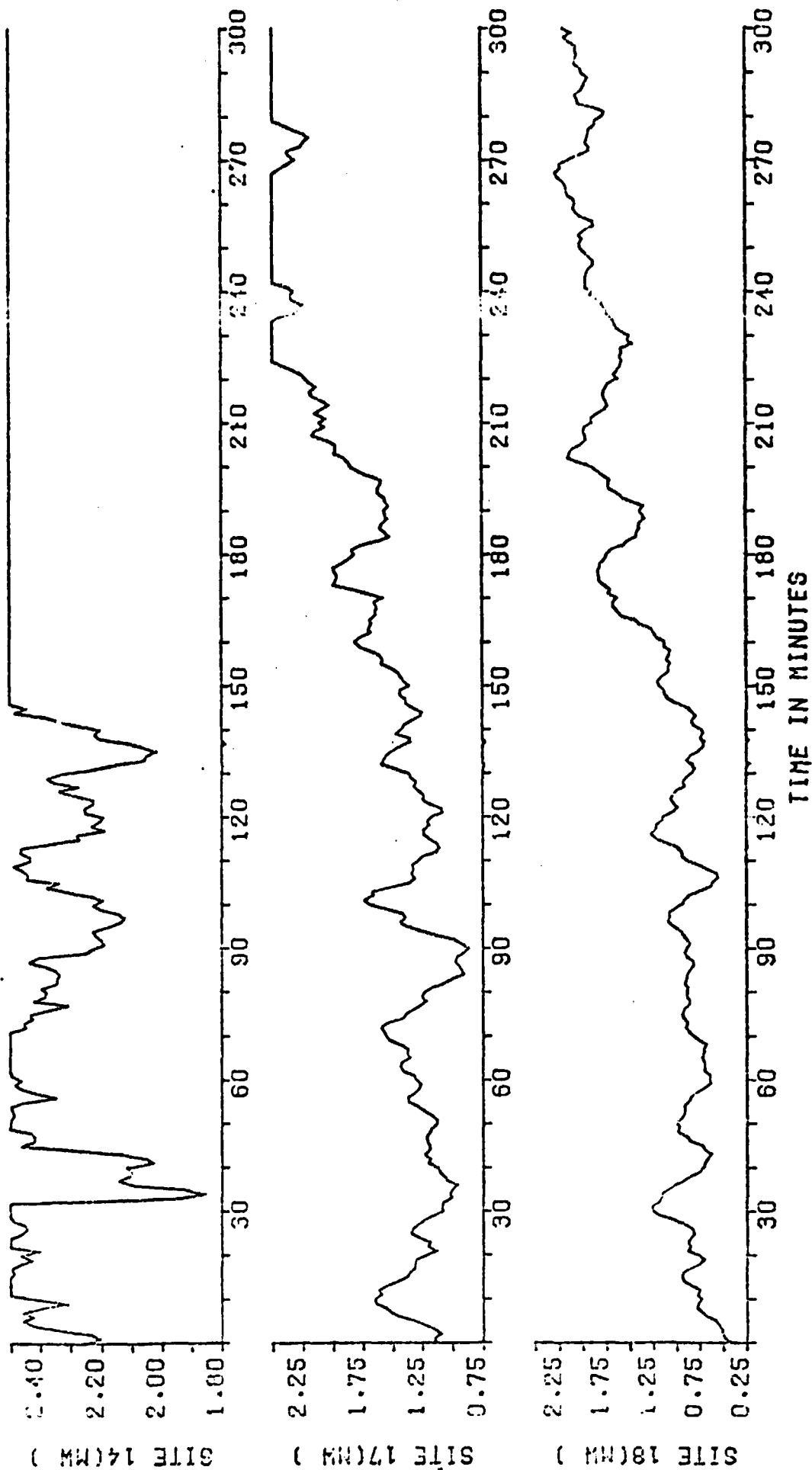
TABLE 9. TABLE OF ERROR FOR ACTUAL WIND POWER ON A SINGLE WIND TURBINE FOR FILTERING THE WIND SPEED WITH 5, 10, AND 30 MINUTE SMOOTHING INTERVALS.

SITE NO.	MEAN ERROR BETWEEN 5 MINUTE FILTERED AND UNFILTERED DATA	RMS ERROR BETWEEN 5 MINUTE FILTERED AND UNFILTERED DATA
14	.13	.24
17	.27	.36

SITE NO.	MEAN ERROR BETWEEN 10 MINUTE FILTERED AND UNFILTERED DATA	RMS ERROR BETWEEN 10 MINUTE FILTERED AND UNFILTERED DATA
14	0.132	0.247
17	0.283	0.371

SITE NO.	MEAN ERROR BETWEEN 30 MINUTE FILTERED AND UNFILTERED DATA	RMS ERROR BETWEEN 30 MINUTE FILTERED AND UNFILTERED DATA
14	0.141	0.272
17	0.317	0.419

FIGURE 18. ACTUAL WIND POWER FROM AN 81 WIND TURBINE ARRAY SITED NEAR SITES 14, 17, AND 18 USING 10 MINUTE MOVING AVERAGE FILTERED DATA.

118
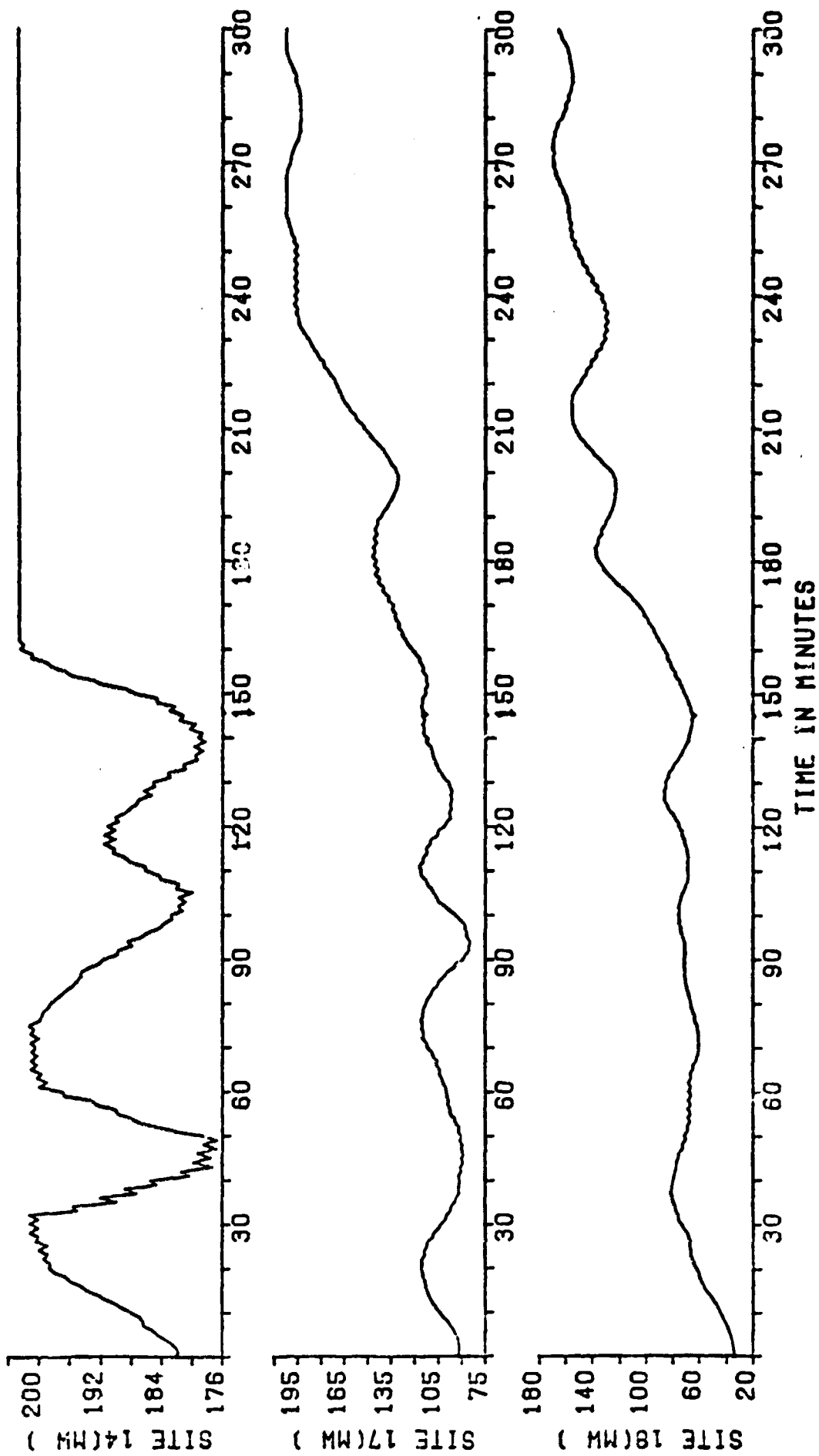
turbine array but 20% from the site 14 wind turbine. The period of the variations has increased for the array power output due to this spatial filtering. Site 17 approaches but never reaches rated array power output although the individual wind turbine reached rated power output at t = 210 minutes. Similarly, site 18 never even approaches rated array power output although the individual wind turbine power approached rated power at t = 300.

Comparison of the array power utilizing an unfiltered, and a filtered wind speed record is shown in Figure 19a-d for 2, 5, 10, and 30 minute smoothing intervals. The filter with 2 minute smoothing interval appear to eliminate the cyclic turbulence-variation and reduce total power output by 4%. The filtering with 5, 10, and 30 minute smoothing intervals significantly reduced the power produced from the array although the shape of the array variation is retained until a 30 minute smoothing interval is used. The percentage reduction in power out of the array can reach 20% due to this filtering but reached greater than 70% for a single wind turbine.

The mean and rms error between array power output based on the unfiltered and a filtered wind speed record is given in Table 10. The mean and rms values increase with smoothing interval and are less than 81 times the values for an individual wind turbine in Table 9. This error increases with smoothing interval more than for the individual wind turbine. The m + 3σ magnitude of 32.1 for site 14 and 41 for site 17 and a five minute interval which is still a significant percentage of the 203 MW array capacity.

5.3 EFFECTS OF FILTERING ON PREDICTED ARRAY POWER

The previous section investigated the effect of filtering of an actual wind speed record (at a meteorological tower site in the SESAME array) on the power out of a fictitious 81 turbine array sited on a 9 mile x 9 mile square area behind the meteorological tower. It was found that filtering significantly increased the power of an individual wind turbine and out of an array and significantly reduced the cyclic variation out of a turbine and out of an array.

Prediction of wind speed is a spatial filtering process where the wind speed at several sites are weighted and delayed and then summed to produce the predicted wind speed record. Thus, filtering these wind speed records before the predicted wind speed record and the predicted power out of the array is computed will be shown to have very little effect compared to the filtering of the actual wind speed record which is then used to simulate the power out of an array. The reduction of the effects of filtering the reference wind speed records on the predicted wind power variation out of the array is due to inherent spatial filtering in the wind speed prediction process. This spatial filtering of the wind speed prediction will be shown to increase the power predicted out of the array compared to that produced from the actual wind speed record. This optimism in predicting the trend could reduce the spinning and operating reserve provided by the unit commitment and thus the reliability of the power system if wind prediction

error $Q_W^+(k + j/4 - 1)$ were set to zero in the unit commitment procedure

FIGURE 19A. COMPARISON OF WIND ARRAY POWER AT SITE 14 USING 2 MINUTE MOVING AVERAGE AND UNFILTERED DATA.
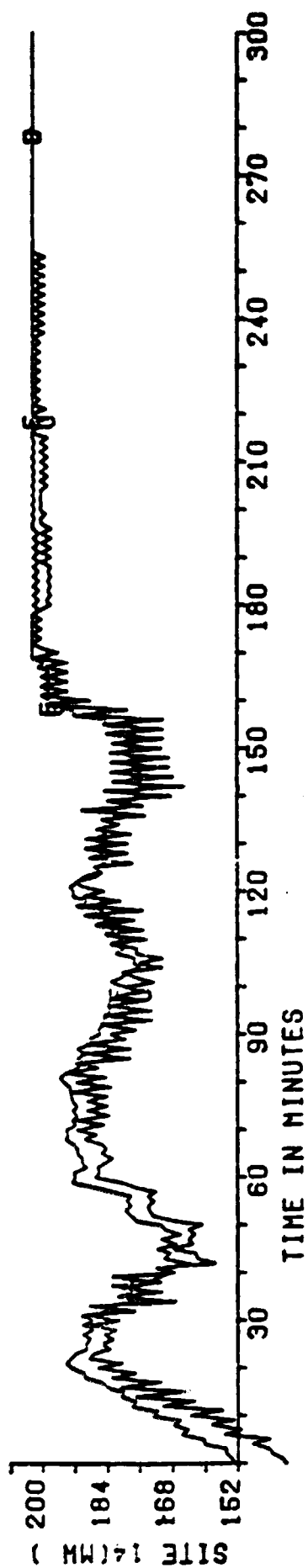
FIGURE 19B. COMPARISON OF WIND ARRAY POWER AT SITE 14 USING 5 MINUTE MOVING AVERAGE FILTERED AND UNFILTERED DATA.
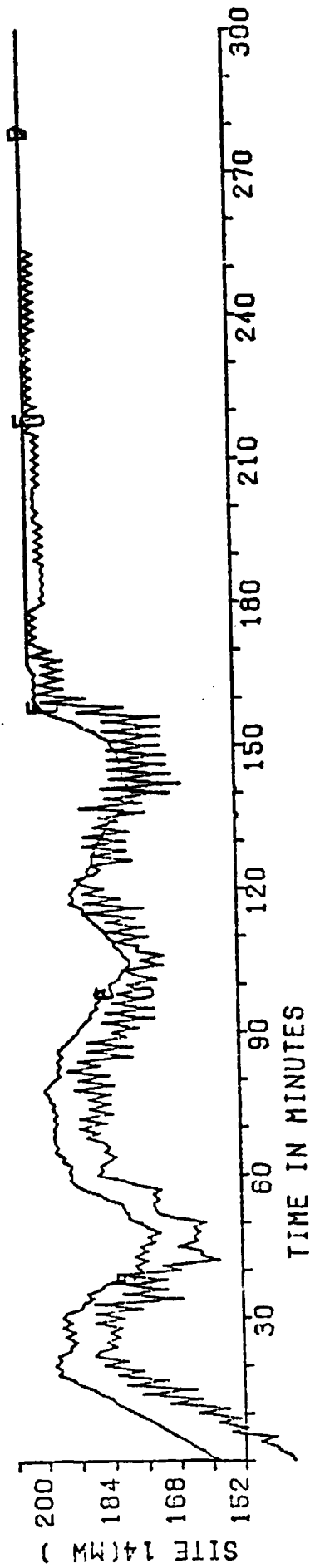
Figure 19c. Comparison of wind array power at site 14 using 10 minute moving average filtered and unfiltered data.
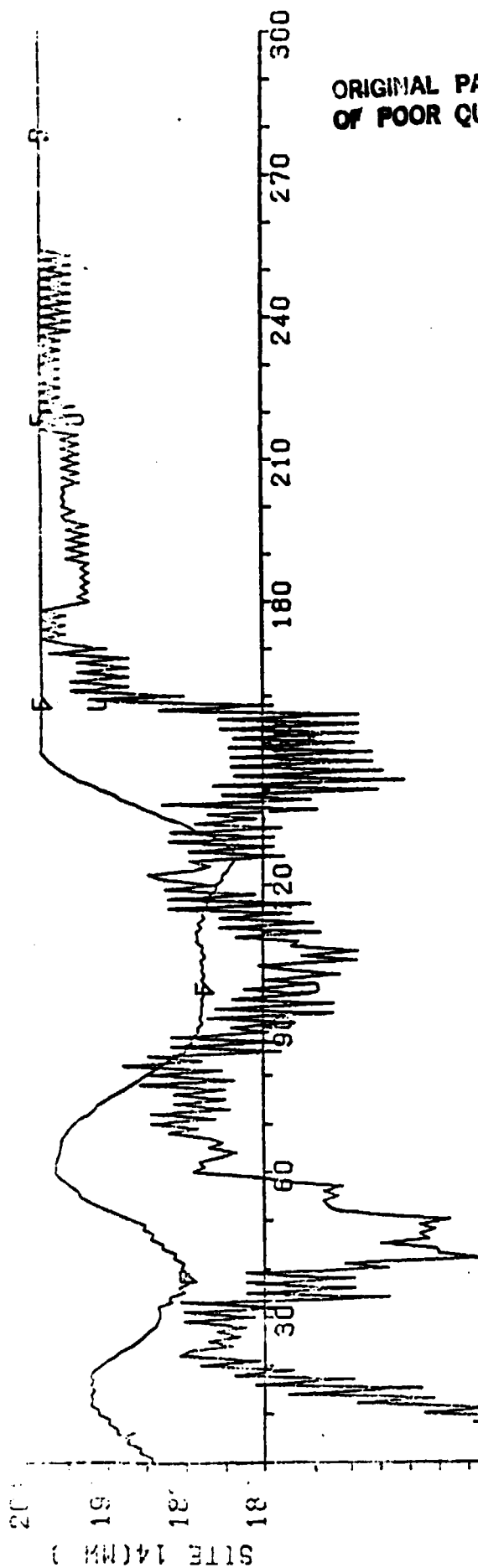
Figure 19d. Comparison of wind array power at site 14 using 30 minute moving average filtered and unfiltered data.

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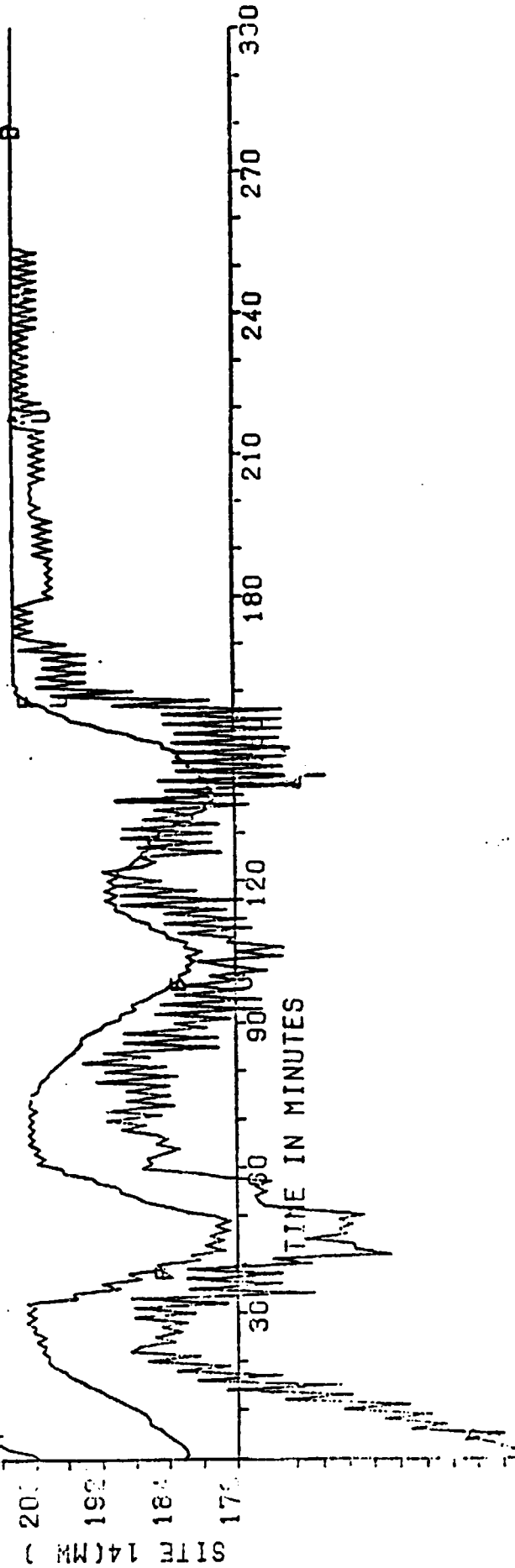
TABLE 10. TABLE OF ERROR FOR ACTUAL ARRAY POWER FOR FILTERING
THE WIND SPEED WITH 5, 10, AND 30 MINUTE SMOOTHING
INTERVALS.

SITE NO.	MEAN ERROR BETWEEN 5 MINUTE FILTERED AND UNFILTERED DATA	RMS ERROR BETWEEN 5 MINUTE FILTERED AND UNFILTERED DATA
14	6.10	3.72
17	8.11	10.98

SITE NO.	MEAN ERROR BETWEEN 10 MINUTE FILTERED AND UNFILTERED DATA	RMS ERROR BETWEEN 10 MINUTE FILTERED AND UNFILTERED DATA
14	7.768	11.791
17	9.037	11.124

SITE NO.	MEAN ERROR BETWEEN 30 MINUTE FILTERED AND UNFILTERED DATA	RMS ERROR BETWEEN 30 MINUTE FILTERED AND UNFILTERED DATA
14	9.307	14.807
17	13.471	16.153

developed in Section 2. $\bar{Q}_W(k + j/4 - 1)$ should not be set to zero but should be based on an estimate on the maximum error in the trend wind power prediction. Thus, this optimism in predicting trend wind power should not affect operating reliability if $Q_W^+(k+j/4-1)$ is set proportional to the wind power prediction error.

The inherent spatial filtering in the wind speed prediction process will also be shown to eliminate the cyclic variation in the actual wind power variation.

The predicted power out of an array at site 14 utilizing filtered and unfiltered reference wind speed records for wind speed prediction is shown in Figure 20a-c for 2, 5, and 10 minute smoothing intervals. The difference between the array power utilizing filtered and unfiltered records at these reference sites for wind speed prediction and thus predicted wind array power variation is negligible as shown in Figures 20a-c.

The mean and rms error between unfiltered and filtered wind array power variations are tabulated in Table 11 for actual and predicted wind power variation. The mean and rms error for predicted power at sites 14, 17, 18 are less than for the actual wind power due to inherent filtering provided by the spatial filtering in the prediction process.

5.4 COMPARISON OF PREDICTED AND ACTUAL WIND ARRAY POWER

The previous two sections have shown that the effect of filtering the wind speed record at a site used to simulate the actual wind array power is large. Filtering the reference wind speed record used to predict the wind speed at that site, which is then used to simulate predicted array power, was shown to have little effect on predicted array power variation. A comparison of actual and predicted wind power variation must thus be made when no filtering is performed on the actual wind speed record at the site or on the reference wind speed records used to predict wind speed at the site.

A comparison of the actual and predicted wind array power at site 14 is plotted in Figure 21. The mean and rms error is 5.78 MW and 9.70 MW respectively. This plot shows the high frequency cyclic variation in the actual which is not present in the predicted wind power variation due to the spatial filtering of the wind speed prediction process. The predicted wind power record is consistently greater than the actual wind power record as expected due to the inherent spatial filtering in the wind speed predictor. The $m + 3\sigma$ error = 34.5 MW which is approximately 15% of the array capacity. Use of only one measurement site to simulate wind array power variation can cause additional error as shown in the next subsection and in Section 6 of this report.

FIGURE 20A. COMPARISON OF PREDICTED WIND ARRAY POWER AT SITE 14 USING 2 MINUTE MOVING AVERAGE FILTERED AND UNFILTERED DATA.

MEAN ERROR = 1.128

R.M.S. ERROR = 2.05
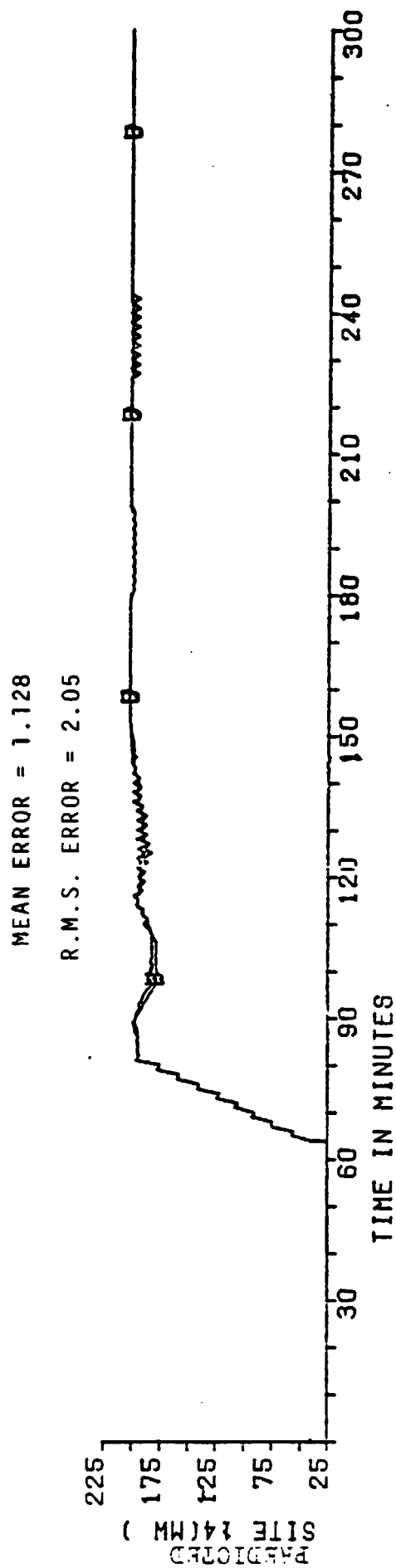
FIGURE 20B. COMPARISON OF PREDICTED WIND ARRAY POWER AT SITE 14 USING 5 MINUTE MOVING AVERAGE FILTERED AND UNFILTERED DATA.

MEAN ERROR = 1.861

R.M.S. ERROR = 3.277

126
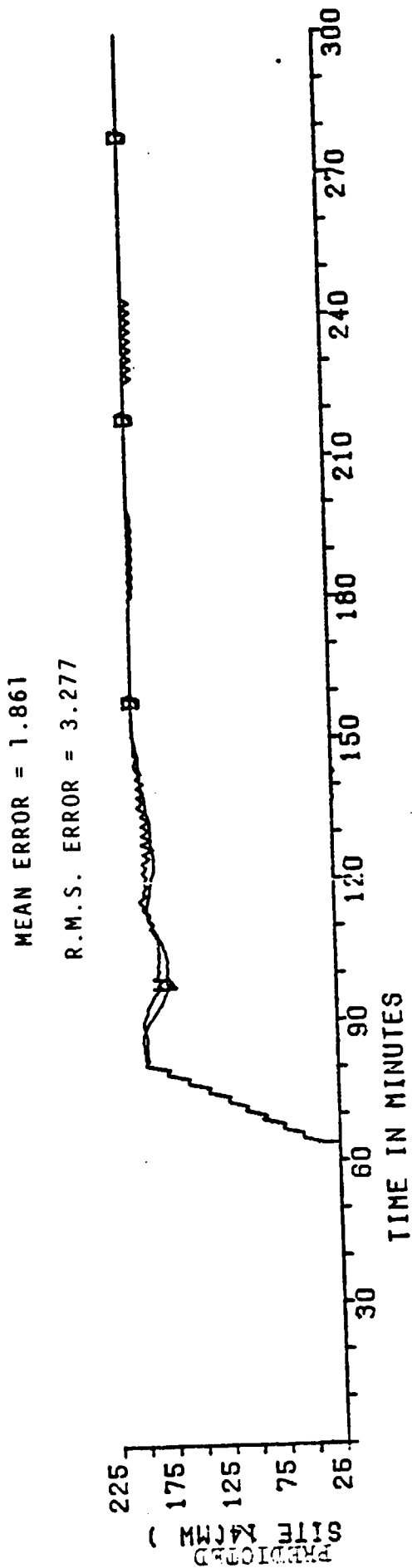
FIGURE 20c. COMPARISON OF PREDICTED WIND ARRAY POWER AT SITE 14 USING 10 MINUTE MOVING AVERAGE FILTERED AND UNFILTERED DATA.

MEAN ERROR = 2.377

R.M.S. ERROR = 4.325

127
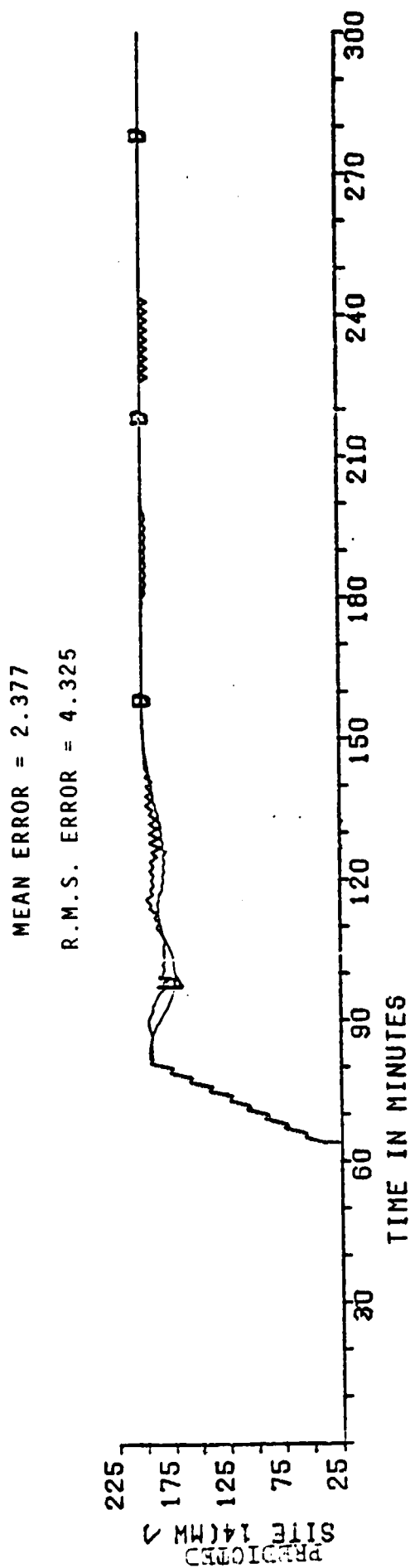
TABLE 11. ERROR IN ACTUAL AND PREDICTED ARRAY POWER VARIATION FOR UNFILTERED AND 2, 5, AND 10 MINUTE FILTERED WIND MEASUREMENT RECORDS.

SITES	ACTUAL						PREDICTED					
	MEAN ERROR			RMS ERROR			MEAN ERROR			RMS ERROR		
	2	5	10	2	5	10	2	5	10	2	5	10
	MINUTE FILTERED			MINUTE FILTERED			MINUTE FILTERED			MINUTE FILTERED		
14	---	6.10	7.762	---	8.72	11.791	1.128	1.861	2.377	2.050	3.277	4.325
17	---	8.11	9.057	---	10.98	11.124	4.49	7.751	9.20	5.40	8.630	11.18
18	---	---	---	---	---	---	3.73	6.21	8.629	4.72	7.66	10.126

Figure 21. Comparison of actual and predicted wind power at Site 14.
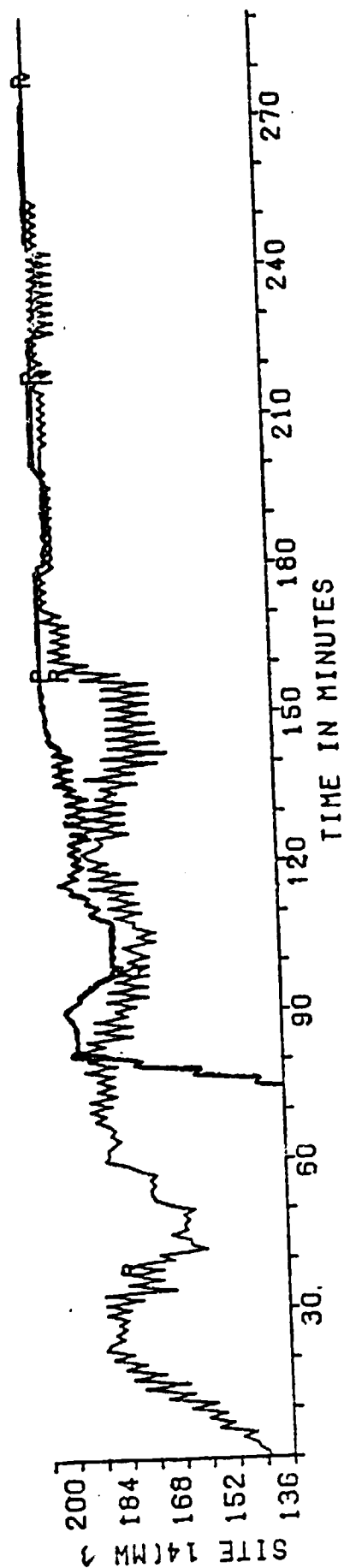
5.5 EFFECT OF SEVERAL WIND SPEED PREDICTION RECORDS ON WIND ARRAY POWER PREDICTIONS

The wind turbine array are generally spread out over a large geographical area due to the fact that one is cautioned to site wind turbines no closer than ten blade diameters apart. Although wind turbines may be sited more closely than this guideline, not all sites may have excellent wind resource and not all of the sites with excellent resources may be available due to other uses, and environmental concerns. Thus, a one mile on a side matrix sited away may be typical for some areas.

The 81 wind turbine array with a matrix one mile on a side separation between wind turbine covers a 9 mile by 9 mile area. Our research on wind speed prediction in Section 4 has shown that the average and rate of change of wind speed at sites 10 miles apart can be quite different. Thus, it appears that one wind measurement site will not be sufficient to adequately predict wind speed and power at all wind turbines in an array covering 81 square miles due to the fact that average wind speed, wind speed variation, and rate of change of wind speed varies widely over the array and no attempt is made to assess this geographical variation if one wind measurement site is used.

The research performed in this section is to confirm the need for more than one wind speed prediction site in each wind turbine cluster. Wind power will be predicted for an 81 wind turbine array sited at Sites 14 and 17 as shown in Figure 22. The predicted wind speed at Sites 12 and 14 will be utilized to simulate array power at the array at Site 14. The predicted wind speeds at Sites 15 and 18 will be utilized to simulate the power out of the array at Site 18. Note the measurements at each array are at the front and back of the array in the direction of meteorological event propagation for the front observed from 1:00 - 6:00 p.m. on May 2, 1979 on these sites. Sites 23 and 25 are utilized as reference measurement sites to predict wind speed at 15, 18, 12, and 14 rather than reference Sites 19, 22, 23, and 25 utilized in the previous work. The wind speed record utilized to predict wind speed and thus simulate predicted power or the actual wind speed used to simulate actual power are filtered with a 2 minute smoothing interval for all cases in this section.

The actual and predicted array power at Site 14 utilizing only the actual and predicted wind speed at Site 14 is shown in Figure 23. The mean and rms errors are 6.93 and 10.93 but the predicted wind power is less than the actual wind power record. This result may be explained by the fact that only two reference sites are utilized that are very close together and have similar wind speed records. The spatial filtering of the wind speed prediction process is thus quite limited and explains why the predicted power is not larger than the actual power. The $m + 3\sigma$ error of 40 is 20% of the total array capacity.

The actual power out of the array at Site 14 utilizing solely the measurement record at Site 14 along with the predicted array power utilizing the average of the predicted wind speed at Site 12 and 14 is plotted in Figure 24. The mean and rms error is 5.99 and 8.76 but the predicted power is now larger than the actual array power. The predicted wind speed at Site
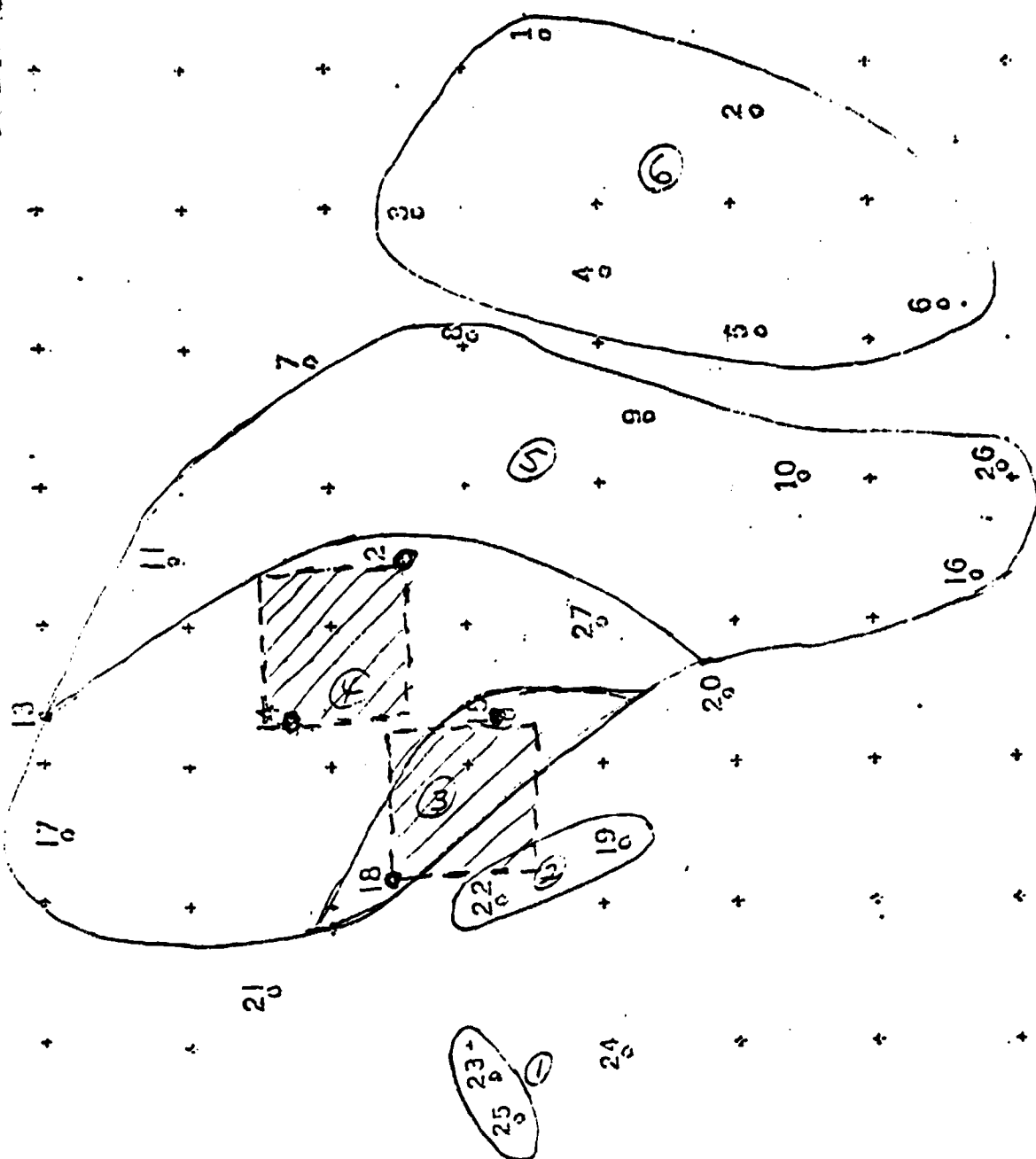
Figure 22. Map of wind turbine array siting for the wind turbine array that utilizes measurements at Sites 12 and 14 and for the array that utilizes measurements at Sites 15 and 18.

FIGURE 23. COMPARISON OF ACTUAL AND PREDICTED WIND POWER THAT UTILIZES WIND RECORDS AT SITE 14.

MEAN ARROR = 6.93

R.M.S. ERROR = 10.53

TIME IN MINUTES(REFRENCES FOR PREDICTION ARE SITES 23 & 25)
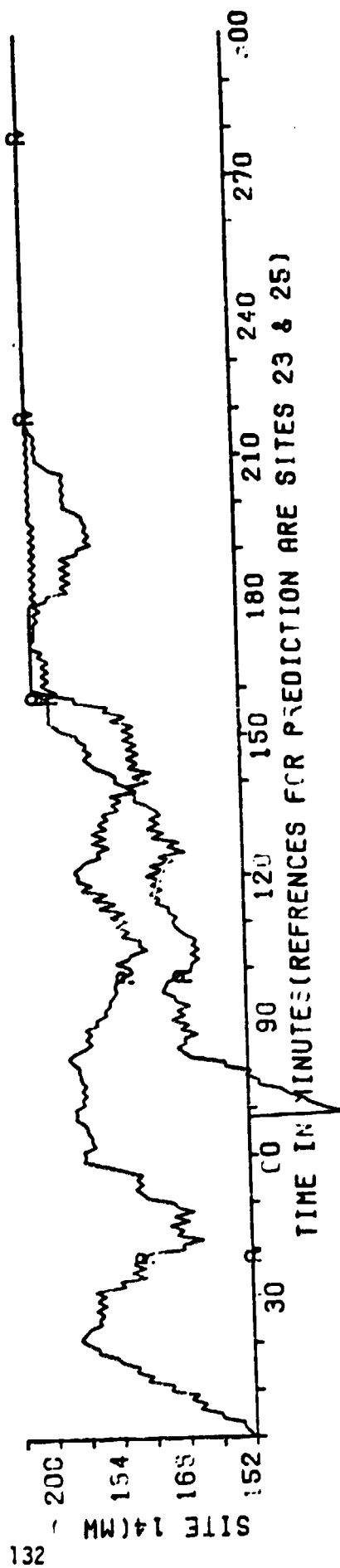
FIGURE 24. COMPARISON OF ACTUAL WIND ARRAY POWER BASED ON WIND RECORD AT SITE 14 AND THE PREDICTED WIND ARRAY POWER ON AN AVERAGE OF WIND RECORDS AT SITES 12 AND 14.

MEAN ERROR ≠ 5.998

R.M.S. ERROR ≠ 8.76

TIME IN MINUTES(REFRENCES FOR PREDICTION ARE SITES 23 & 26)
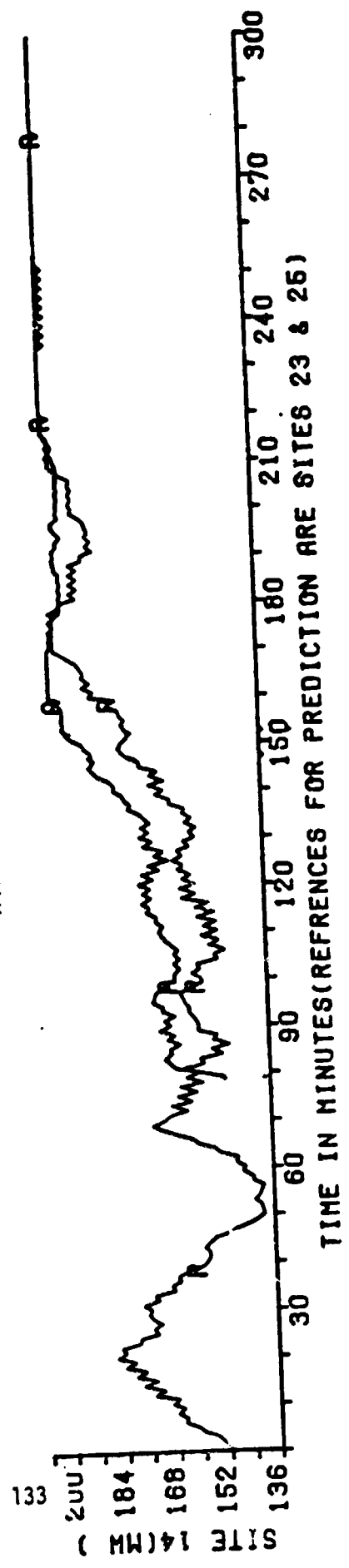
12 is larger than at Site 14 raising the power out of the array by an average of 12 megawatts. The shape of the predicted array power utilizing two wind prediction sites is closer to the actual power based on only Site 14. A comparison of the actual and predicted power utilizing both an average of the actual and predicted wind speeds was not carried out on this data but was carried out on the Site 18 array.

The power out of the array using the actual and predicted wind speed at Site 18 is shown in Figure 25. The predicted wind power is greater than the actual wind power as expected due to the spatial filtering associated with the prediction process. The mean and rms error is 19.14 and 22.67 which is very large. The error $m + 3\sigma = 87$ MW which is 40% of the array capacity. Although these errors are large, Figure 24 indicates the predicted power tracks the actual power record ramp increase but the site specific cyclic variations with a 30 minute period are not predicted. The actual and predicted power from the array based on an average of the actual and predicted wind speed records at Sites 15 and 18 is plotted in Figure 26. The predicted power is again larger than the actual wind power from the array. The mean and rms errors are 18.41 and 21.94 and the $m + 3\sigma$ error = 84.5 is large. The most important difference utilizing the two Sites 15 and 18 rather than just Site 18 is very substantial change in power out of the array. The power out of the array may be as much as 35 MW more utilizing the average wind speed at 2 sites than utilizing one site. A substantial increase in power output utilizing the average wind speed at 2 sites compared to utilizing just a single measurement or predicted wind speed was also observed on the Site 14 array. The wind speed at Site 15 was larger and had different site specific variations than at Site 18 and thus the use of two sites reduced the magnitude of these site specific effects of both the actual and predicted wind array power records utilizing the average of the wind speed at two sites.

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FIGURE 25. COMPARISON OF ACTUAL AND PREDICTED WIND ARRAY POWER USING WIND RECORDS AT SITE 18.

MEAN ERROR ≠ 19.14
R.M.S. ERROR = 22.67

TIME IN MINUTES(REFRENCES FOR PREDICTION ARE SITES 23 & 25)

SITE 18(MW)

135
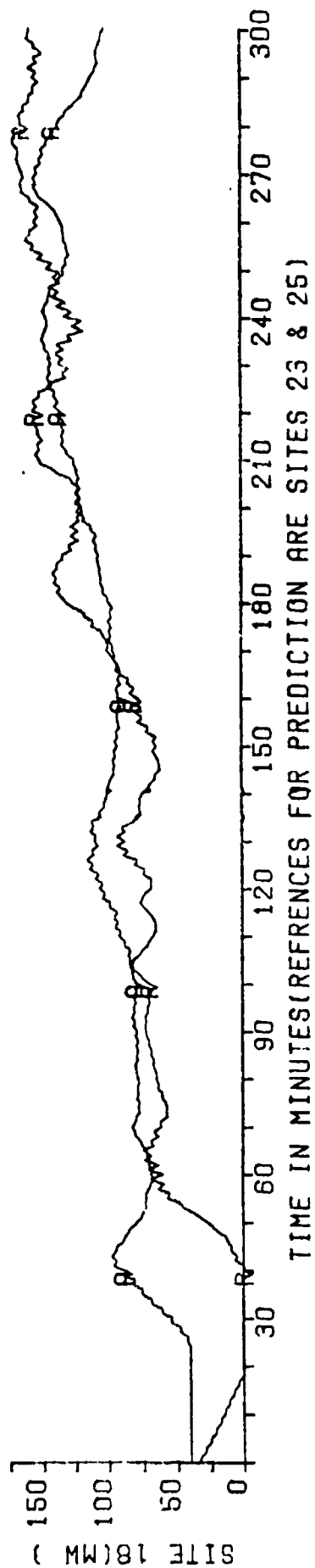
FIGURE 26. COMPARISON OF ACTUAL AND PREDICTED ARRAY POWER BASED ON AN AVERAGE OF WIND RECORDS AT SITES 18 AND 15.

MEAN ERROR = 18.41

R.M.S. ERROR = 21.94

TIME IN MINUTES(REFRENCES FOR PREDICTION ARE SITES 23 & 25)

SITE 18(MW)

136
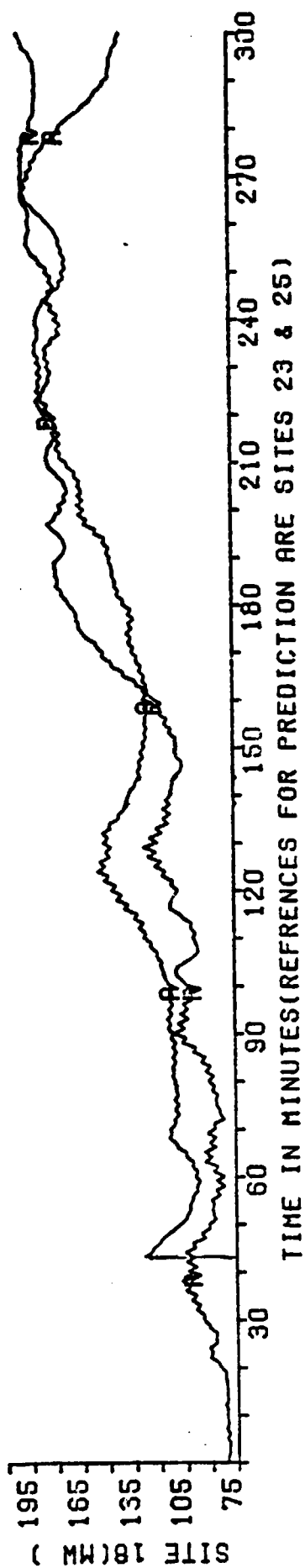
SECTION 6

COMPARISON AND ACCURACY OF
WIND ARRAY POWER SIMULATION METHODS

The results of the previous section indicate that utilizing several
reference sites to predict wind speeds at one or more sites in a wind turbine
array reduces site specific effects of any specific reference site but
effectively performs a spatial filtering of the wind speed profile associated
with the specific meteorological event. The spatial filtering reduces the
level of the power predicted from an array in a manner similar to time
filtering of the predicted wind speed records. This negative bias in the
predicted wind power is unavoidable if several reference sites are utilized to
predict wind speed at sites in the array.

A preliminary study of the effects of utilizing several prediction sites
to simulate the wind power from an array of wind turbines was conducted. The
results suggested that each prediction site can have very different mean,
standard deviation, and site specific cyclic variations even though the sites
may be within five miles of each other. These site specific effects
greatly effect wind array power if only one site is used but the site
specific effects are reduced if several sites are used. It is clear that
utilizing as many prediction sites as possible would increase array power
prediction accuracy. Since the number of prediction sites is limited, due
to cost of instrumentation and communication hardware for measurements at
each additional prediction site and the computational requirements for
producing each additional wind speed prediction record, care must be uti-
lized in simulating array power variation to minimize the site specific
effects and minimize the wind array power prediction error from a limited
number of wind prediction sites.

The results thus indicate a more complete study is necessary to assess
the accuracy and the differences between the array power obtained using six
different methods of simulating wind array power variation. These different
simulation methods utilize one or several wind prediction sites to simulate
array power variation.

Figure 27 shows a wind turbine array composed of N wind turbines each
sited at a distance $\{d_n\}_{n=1}^N$ from the reference wind turbine in the array that is
the first wind turbine to be effected by the wind variation of the
meteorological event. The J wind measurement sites are sited at a distance D_j
from the reference wind turbine in the array. The wind speed record at site j
$W_j(t)$ is reflected to occur at the reference wind turbine site by advancing
the record by $T_j = D_j/V_o$ to produce $W_j(t + T_j)$ where V_o is the speed of
propagation of the meteorological event.

The predicted wind power from the set of N wind turbine based on the
predicted wind speed record is
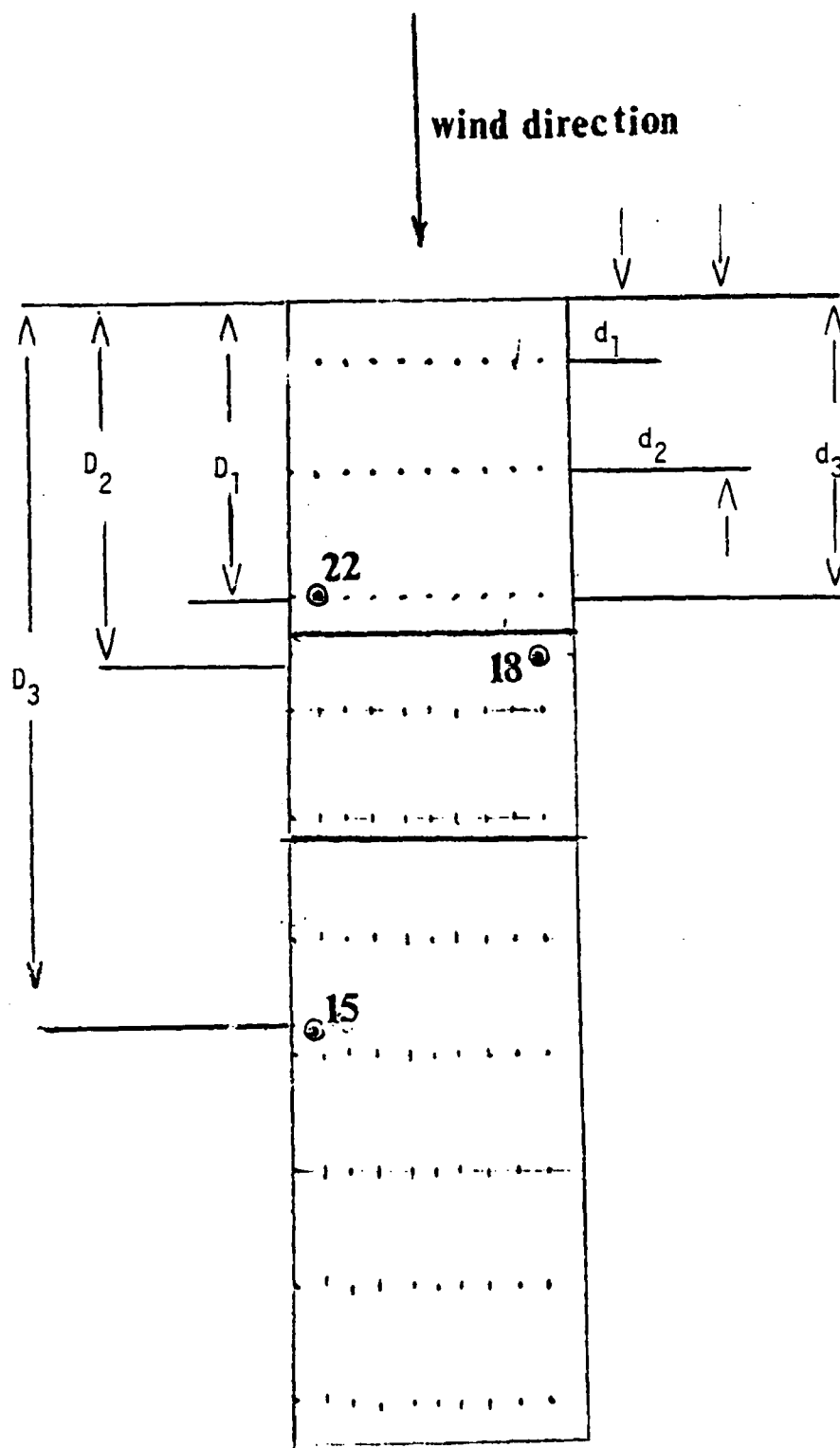
FIGURE 27. WIND TURBINE ARRAY CONFIGURATION SHOWING DISTANCES D_J FROM WIND PREDICTION SITES AND DISTANCE D_N TO WIND TURBINE.

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$$P_{AI}(t) = \sum_{n=1}^{N} P_j(t + T_j - t_n)$$

where the power from the reference wind turbine is

$$P_j(t + T_j) = f\{W_j(t + T_j)\}$$

and where $f(\cdot)$ is the nonlinear algebraic relationship between wind power versus wind speed for a particular wind turbine model. The wind array power array (t) is the sum of the power from each of the individual wind turbines in the array $P_j(t + T_j = t_n)$ produced by delaying the simulated wind power $P_j(t + T_j)$ at the reference wind turbine site where $t_n = \dfrac{d_n}{V_o}$.

The second method averages the wind speed record reflected to the site of the reference wind turbine record

$$W_A(t) = \frac{1}{J} \sum_{j=1}^{J} W_j(t + T_j)$$

The power produced by a wind turbine from this average wind speed record is

$$P_A(t) = f\{W_A(t)\}$$

The power from the array of wind is then produced by delaying and summing the averaged reference wind turbine power record $P_A(t)$ for each wind turbine in the array

$$P_{AII}(t) = \sum_{n=1}^{N} P_A(t - t_n)$$

$$= \sum_{n=1}^{N} f\left(\frac{1}{J} \sum_{j=1}^{J} W_j(t + T_j - t_n)\right)$$

The third method simulates the power from each of the wind speed records reflected to the site of the first wind turbine to be effected by the meteorological event.

$$P_j(t + T_j) = f(W_j(t + T_j))$$

An average wind power record

$$\overset{*}{P_A}(t) = \frac{1}{J} \sum_{j=1}^{J} P_j(t + T_j)$$

is then produced. The array power is obtained by delaying and summing the average reference wind turbine record for each wind turbine in the array

$$P_{AIII}(t) = \sum_{n=1}^{N} P_A^*(t - t_n)$$

$$= \frac{1}{J} \sum_{n=1}^{N} \sum_{j=1}^{J} f(W(t + T_j - t_n))$$

The fourth method determines the power from the subset of wind turbines closest to each wind prediction site j based on the wind speed prediction record $W_j(t)$. The wind measurement sites j are assumed to be ordered based on distance $D_j > D_{j-1}$ from the reference wind turbine site. Similarly, the wind turbine sites n are assumed to be ordered based on the distances $d_n > d_{n-1}$ from the reference wind turbine site. The jth subarray of wind turbines that utilize wind prediction record $W_j(t)$ are located in the interval

$$\frac{D_{j-1}+D_j}{2} \le d \le \frac{D_j+D_{j+1}}{2}$$

as shown in Figure 27. Defining

$$N(j) = \begin{cases} 0 & j=1 \\ \max\{n/d_n < \dfrac{D_j+D_{j+1}}{2}\} & j \ne 1 \end{cases}$$

the wind turbines n belonging to the jth subarray satisfy

$$N(j) < n \le N(j + 1)$$

The power from the jth subarray is

$$P_{sj}(t) = \begin{cases} \displaystyle\sum_{n=N(J-1)+1}^{N} P_J(t + T_j - t_n) & j = J \\[4ex] \displaystyle\sum_{n=N(j-1)+1}^{N(j)} P_j(t + T_j - t_n) & j = 2,3,\dots,J-1 \\[4ex] \displaystyle\sum_{n=1}^{N(1)} P_1(t + T_1 - t_n) \end{cases}$$

where

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$$P_j(t) = f\{w_j(t)\}$$

$$t_n = \begin{cases} \dfrac{d_n - \dfrac{D_{j+1}+D_j}{2}}{V_o} & j \neq 1 \\[4mm] \dfrac{d_n}{V_o} & j = 1 \end{cases} \qquad (12)$$

$$T_j = \begin{cases} \dfrac{D_j - \left(\dfrac{D_j+D_{j-1}}{2}\right)}{V_o} & j \neq 1 \\[4mm] \dfrac{D_1}{V_o} & j = 1 \end{cases} \qquad (13)$$

The values of T_j for each array are chosen so that wind measurement site j within subarray j is reflected to the boundary $\dfrac{D_j+D_{j-1}}{2}$ between subarrays j-1 and j. The wind turbine power record $P_j(t + T_j)$ at the boundary between subarray j-1 and j is then delayed by t_n^j based on the distance of the wind turbine site n in subarray j from the boundary between subarrays j-1 and j and summed for each wind turbine site in that subarray to produce $P_{sj}(t)$. The power out of the J subarrays that constitute the array is the sum of the subarray power

$$P_{AIV}(t) = \sum_{j=1}^{J} P_{sj}(t)$$

The fifth method of simulating power out of the array again simulates power out of each subarray separately and then sums the power out of all subarrays to produce the power out of the array. The jth subarray of wind turbines utilize an averaged wind prediction record

$$W_{jj+1}(t) = \frac{1}{2} [W_j(t) + W_j(t + T_{j+1} - T_j)]$$

and cover the same subarea defined for the previous method

$$\frac{D_{j-1}-D_j}{2} \leq d \leq \frac{D_{j+1}+D_j}{2}$$

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The wind speed prediction record $W_{jj+1}(t)$ is the average of the record $W_j(t)$ and the record $W_{j+1}(t)$ advanced by $T_{j+1} - T_j$ to occur at site j.

The power produced based on this averaged wind speed record for subarray j is

$$P_{jj+1}(t) = f(W_{jj+1}(t))$$

The power from the jth subarray is obtained using the same method used in method 4 where $P_j(t)$ is replaced by $P_{jj+1}(t)$ and thus

$$P_{sj}(t) = \begin{cases} \sum_{n=1}^{N(1)} P_{12}(t + T_1 - t_n) \\\\ \sum_{n=N(j-1)+1}^{N(j)} P_{jj+1}(t + T_j - t_n) \qquad j=2,3,\ldots,J-1 \\\\ \sum_{n=N(J-1)+1}^{N(J)} P_{J-1,J}(t + T_J - t_n) \end{cases}$$

where t_n and T_j are defined in (12) and (13). The power out of the array is again the sum of the power out of the subarrays

$$P_{AI}(t) = \sum_{j=1}^{J} P_{sj}(t)$$

The sixth method of simulating the power out of an array is very similar to the fifth method. The average power for sites in the jth subarray is

$$P_{jj+1}(t) = \frac{1}{2} [P_j(t) + P_{j+1}(t + T_{j+1} - T_j)]$$

where

$$P_j(t) = f(W_j(t))$$

$$P_{j+1}(t + T_{j+1} - T_j) = f(W_j(t + T_{j+1} - T_j))$$

The power based on the wind prediction site j+1 is advanced by $T_{j+1} - T_j$ to appear as if it occurs at site j.
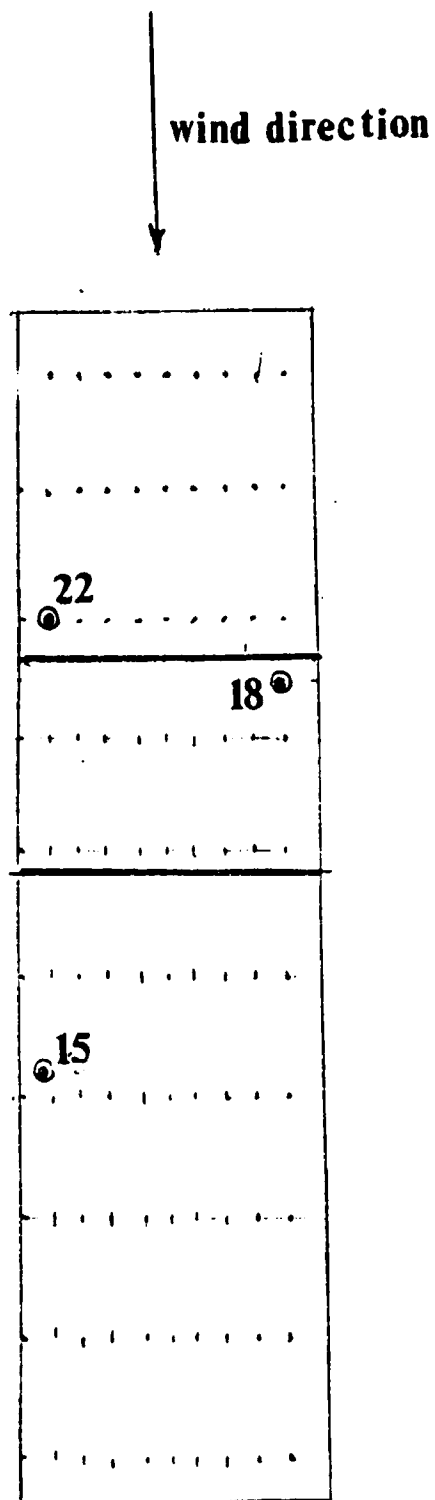
FIGURE 28. VERTICAL WIND TURBINE ARRAY CONFIGURATION SHOWING
LOCATION OF WIND PREDICTION AT SITE 22, 18, AND
15 AND THE 90 WIND TURBINES IN THE ARRAY.

The power from subarray j is then

$$P_{sj} = \begin{cases} \displaystyle\sum_{n=N(j-1)+1}^{N(j)} P_{j,j+1}(t + T_j - t_n) \\[2em] \displaystyle\sum_{n=1}^{N(1)} P_{12}(t + T_1 - t_n) \\[2em] \displaystyle\sum_{n=N(J-1)+1}^{N} P_{J-1,J}(t + T_J - t_n) \end{cases}$$

The power out of the array is the sum of the power out of the subarrays

$$P_{array}(t) = \sum_{j=1}^{J} P_{sj}(t) \qquad\qquad (14)$$

The power from an array of 90 wind turbines sited in a rectangular area of 9 miles by 9 miles, is simulated using the six different methods just described. The spacing between wind turbines in both the latitudinal and longitudinal direction is one mile. The wind prediction sites are located within this rectangular array at sites 22, 18, and 15 as shown in Figure 28. The prediction of the wind speed at sites 22, 18, and 15 is based on wind speed measurements at sites 19 and 23.

The wind power simulated based on the single wind speed measurement at site 22 is shown in Figure 29 along with the power produced based on methods 2 and 3. Methods 2 and 3 produce an average wind turbine based on either averaging the wind speed or wind turbine power records from sites 18, 22, and 15 reflected to the reference wind turbine site. The array power is then produced in both methods by delaying and summing this average wind turbine power record for each wind turbine site in the array. These average wind array power methods 2 and 3 using wind prediction sites 18, 22, and 15 produce wind turbine array power records that are smaller in total power than the wind power record based on method 1 using the single wind speed record at site 22. This result occurred because the magnitude of the wind speed measured at sites 18 and 15 are smaller than the wind speed record measured at site 22. The array power produced based on the single wind speed measurement at 18 and 15 is shown in Figure 29b and 29c, respectively, along with the averaged wind power record based method 2 and 3 using prediction sites 15, 18, and 22. These results show that the wind array power simulated based on single wind speed measurement at either 15 or 18 is approximately 30% less than that produced based on the average of 15, 18, and 22 and approximately half of that produced from the single wind speed measurement at 22. Since all three sites are located in the 90 square mile geographical area containing the 90 wind turbine sites in the array, it is clear that wind turbine array power simulation based on a single wind measurement record correctly captures the shape of the trend change seen in the array but does not accurately capture the magnitude of the power produced by averaging the wind speed or wind turbine power records before simulating wind array power. The very large

FIGURE 29B. COMPARISON OF SIMULATED WIND ARRAY POWER VARIATION USING METHODS 2 AND 3 WITH THE SIMULATED POWER OBTAINED USING A SINGLE RECORD AT SITE 18.

FIGURE 29C. COMPARISON OF SIMULATED WIND ARRAY POWER VARIATION USING METHODS 2 AND 3 WITH THE SIMULATED POWER OBTAINED USING A SINGLE RECORD AT SITE 15.

SIMULATED POWER OBTAINED USING A SINGLE RECORD AT SITE 22.

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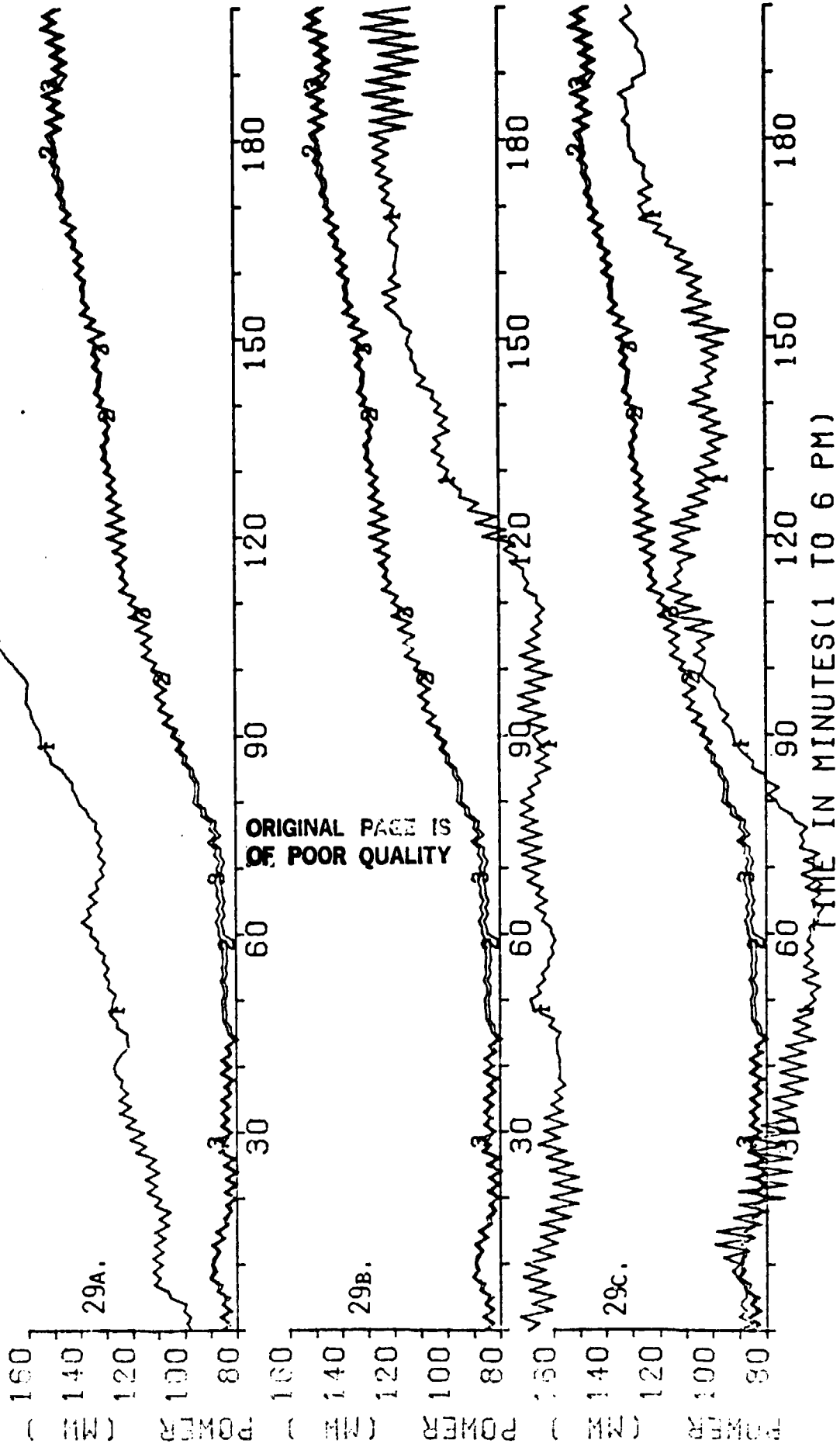
cyclic variations that are measurement site dependent are drastically reduced by averaging the wind speed records as indicated in Figure 29 a, b, and c.

The wind array power based on method 3 is virtually identical to that produced by method 2. This result suggests that the array power produced by first averaging wind speed before simulating the power from an "average wind turbine" gives nearly identical results to simulating power for each wind speed record and then averaging to produce the "average wind turbine record." The array power is produced by delaying the average wind turbine record for each wind turbine and then summing to produce the wind array power record in both methods.

It is clear from the results shown in Figure 29 a, b, c that utilizing several wind measurement widely dispersed geographically within the wind turbine array is necessary to accurately simulate wind array power. The wind array power simulation results for methods 4, 5, and 6 should indicate whether

(1) simulating power from subarrays based solely on the wind measurement site or sites closest to a subarray of wind turbines and then summing to produce a total array wind power record will result in significant differences from averaging wind speed (method 2) or power (method 3) and then simulating the total array wind power;

(2) whether use of closest single measurement site or the average of the closest two wind measurement sites can effect the power produced from a wind array power simulation method.

The results to be presented will show both of the above factors can cause significant changes in the power simulated from an array of wind turbines when the wind speed measurement records at various sites are quite different. The power produced from the array using method 4, 5, and 6 are shown in Figure 30a, b, and c respectively, along with the power simulated from the array using methods 2 and 3. The power produced from the array using method 4 is considerably smaller than for methods 5 and 6 even though the number of wind turbines in the subarrays 1, 2, and 3 for the three methods are identical. Wind speed record 22 is utilized solely in subarray 1 in all three methods and thus the power out of the subarray is identical in all three methods as shown in Figure 31a. An average wind speed record (14) based on $W_{18}(t)$ and $W_{22}(t)$ is utilized to produce subarray power in method 5 and an average of the powers produced based $W_{18}(t)$ and $W_{22}(t)$ is used to produce the subarray power for the second subarray in method 6. The subarray power for the second subarray depends solely on $W_{18}(t)$ for method 4. Since $W_{22}(t)$ is much larger than $W_{18}(t)$, the power produced by method 5 and 6 for subarray 2 are much larger than for method 4 as shown in Figure 31b.

The power produced for subarray 3 is very similar for all three simulation methods as shown in Figure 31c. Method 4 utilizes $W_{15}(t)$ alone to simulate power from the array. Method 5 averages $W_{18}(t)$ and $W_{15}(t)$ to produce power in the third subarray and method 6 averages the power produced based on $W_{15}(t)$ and $W_{18}(t)$. It is clear that since the wind speed records are similar methods 4, 5, and 6 give nearly identical results in subarray 3 from the results in Figure 31c.

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FIGURE 30A. COMPARISON OF SIMULATED ARRAY POWER VARIATION USING METHODS 2, 3, AND 4.

FIGURE 30B. COMPARISON OF SIMULATED ARRAY POWER VARIATION USING METHODS 2, 3, AND 5.

FIGURE 30C. COMPARISON OF SIMULATED ARRAY POWER VARIATION USING METHODS 2, 3, AND 6.

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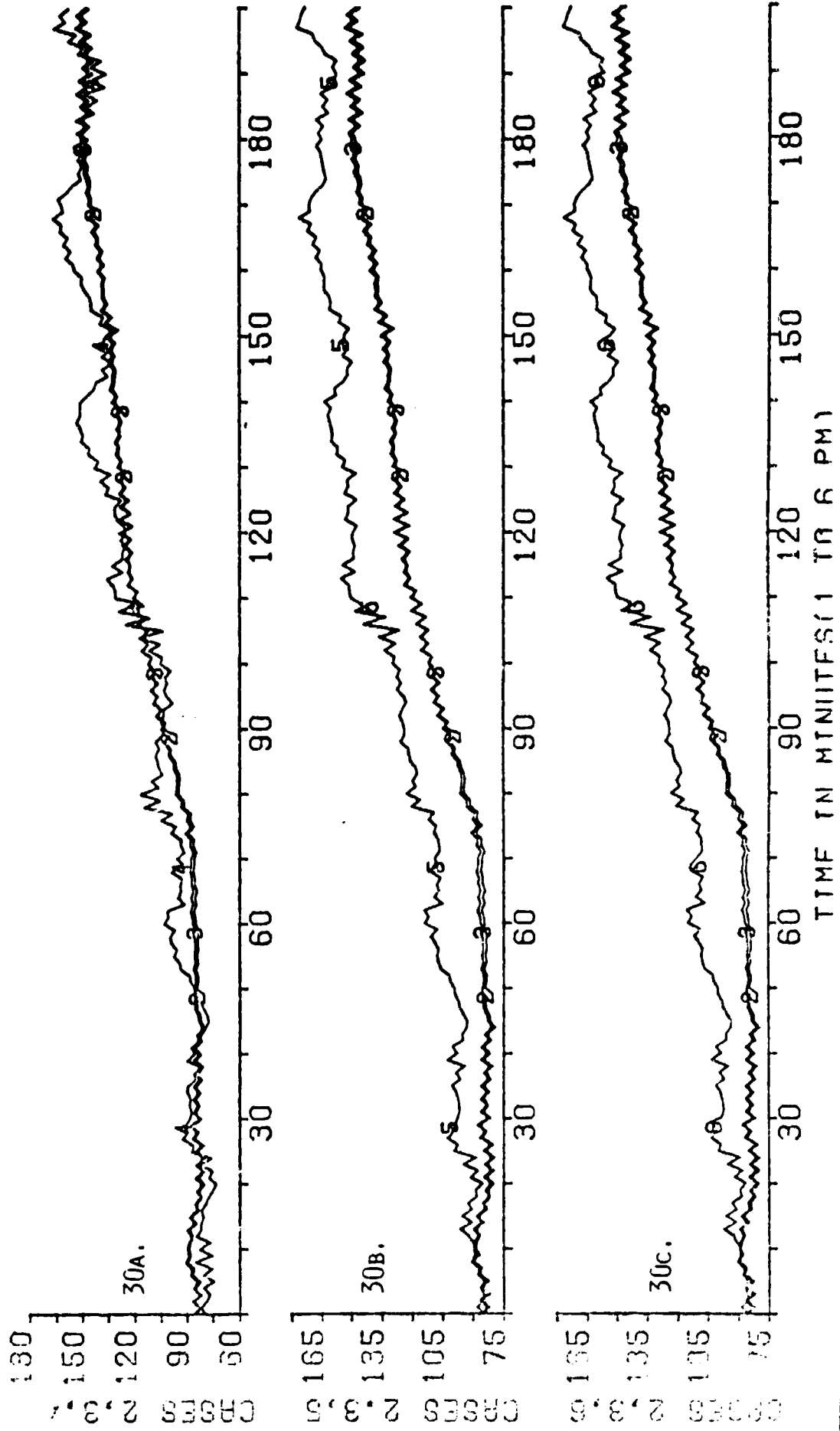
FIGURE 31A. COMPARISON OF SIMULATED POWER VARIATION IN SUBARRAY 1 USING METHODS 4, 5, AND 6.

FIGURE 31B. COMPARISON OF SIMULATED POWER VARIATION IN SUBARRAY 2 USING METHODS 4, 5, AND 6.

FIGURE 31C. COMPARISON OF SIMULATED WIND POWER VARIATION IN SUBARRAY 3 USING METHODS 4, 5, AND 6.

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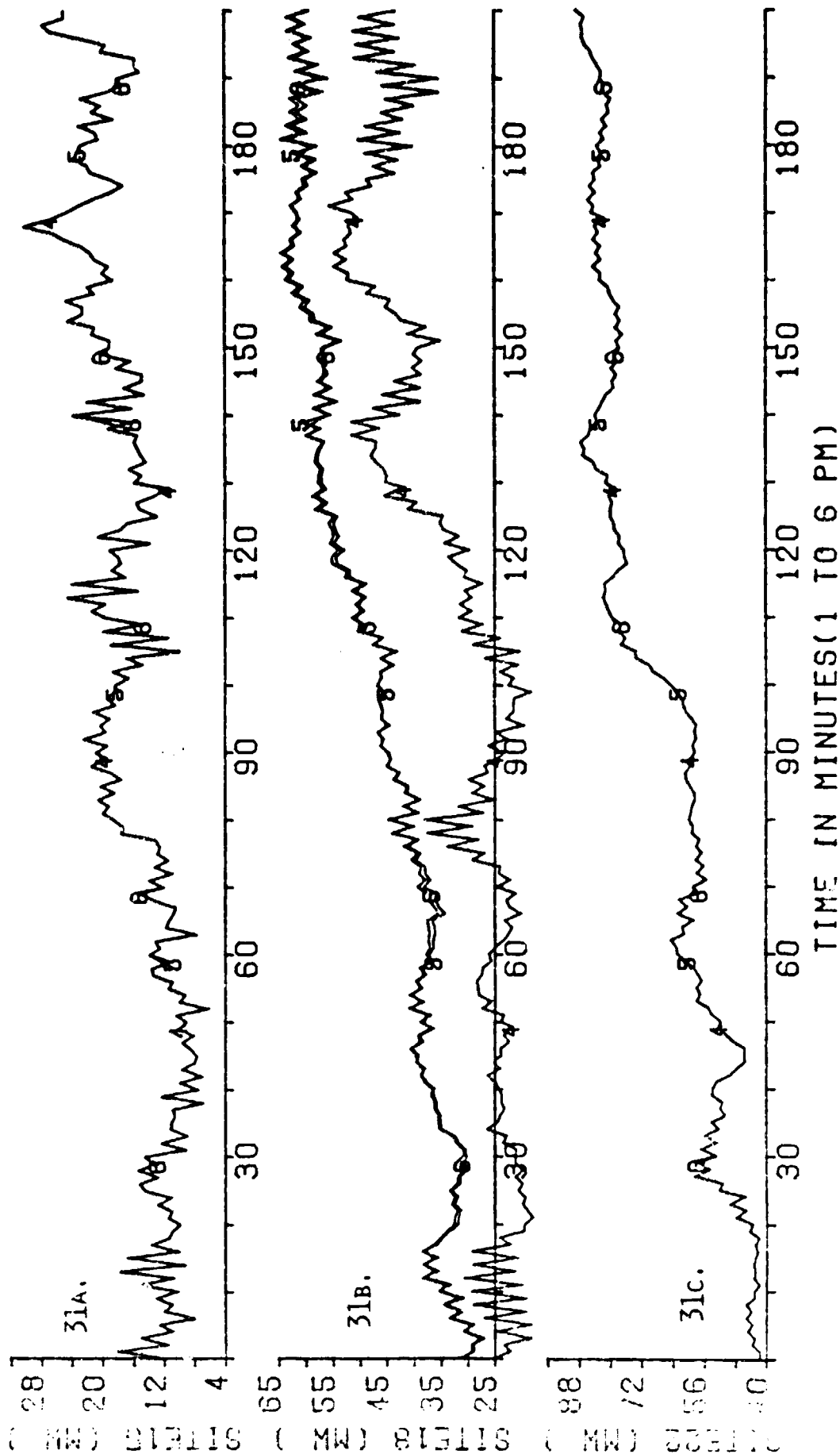
The effect of siting wind turbines in different patterns was investigated. The 90 wind turbines were sited in a horizontal pattern as shown in Figure 32 in addition to the vertical pattern shown in Figure 28. The differences in the array power produced by methods 2-6 for the vertical and horizontal array configurations is shown in Figures 29 and 33 respectively. Note as the number of wind turbines in a straight line normal to propagation of the front increase, the size of the cyclic variations increase the ramp rate of change of power appears to be quite similar on all three siting configurations. The differences between arrays over the simulation methods 2-6 on the vertical array configuration are the same as the differences observed between the simulation methods 2-6 for the horizontal array configuration.

One should attempt to minimize the impact of any one single wind measurement on the power simulated from the array since one cannot be sure of how many wind turbines in an array will have similar wind speeds as a particular wind speed measurement site and one cannot be certain the wind speed measurements at any site are not site specific. In order to minimize the error between the power produced from simulation and power actually produced from the array, each measurement sites effect on total array power should be equal. Thus, the number of wind turbines in each subarray should be equal. Either wind speed at only one site or the wind speed measurement at the closest two sites may be averaged to simulate power in a subarray if the number of wind turbines in the subarrays are equal.
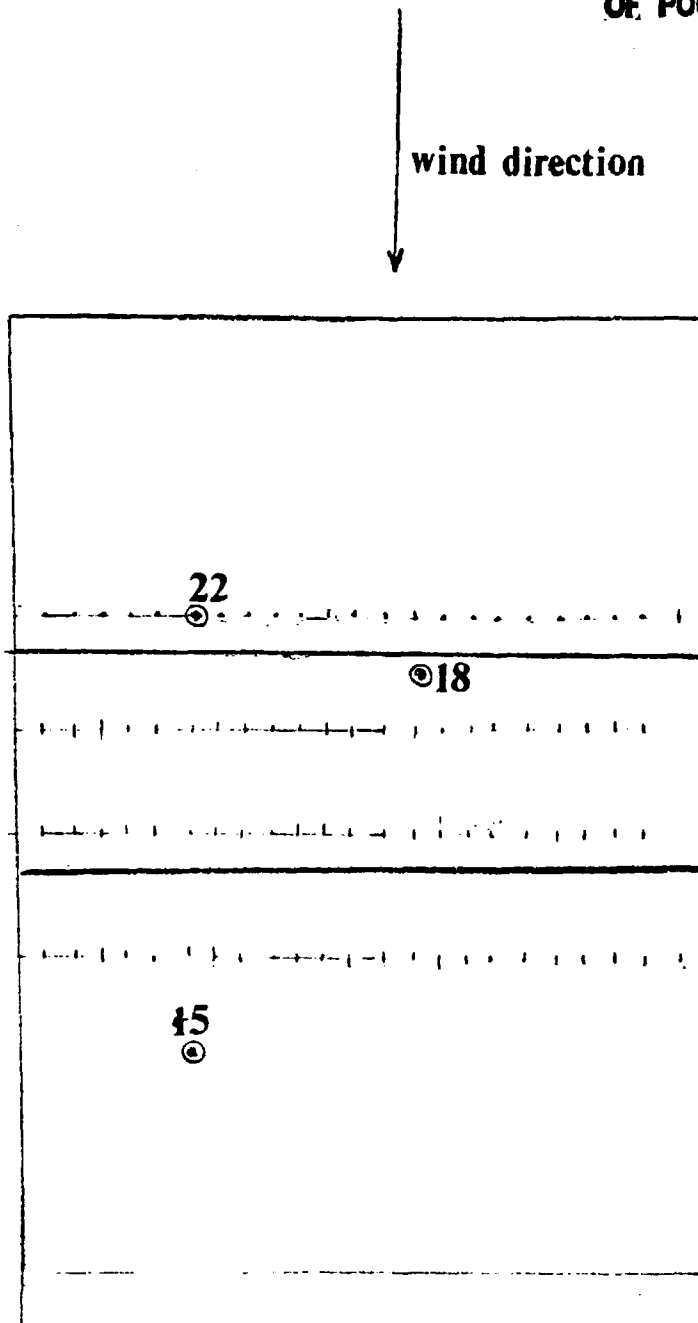
FIGURE 32. HORIZONTAL TURBINE ARRAY CONFIGURATION SHOWING
LOCATION OF WIND PREDICTION SITES AND THE 90
WIND TURBINE ARRAY SITES.

FIGURE 33. COMPARISON OF SIMULATED WIND POWER VARIATION OF METHODS 4, 5, AND 6 WITH POWER SIMULATED USING METHODS 1, 2, AND 3.

SECTION 7

WIND POWER ERROR PREDICTION METHODS

The wind power prediction error will generally exceed 15% of the wind generation level out of the wind turbine array. The wind power prediction error can be as large as the total array generation capacity if low speed and high speed shutdowns of the wind turbines in the array are not predicted. The large storm induced cyclic variations cannot be predicted using the present methodology and have been shown to cause repeated low speed shutdown and startups that very quickly reach wind turbine generation capacity. High speed 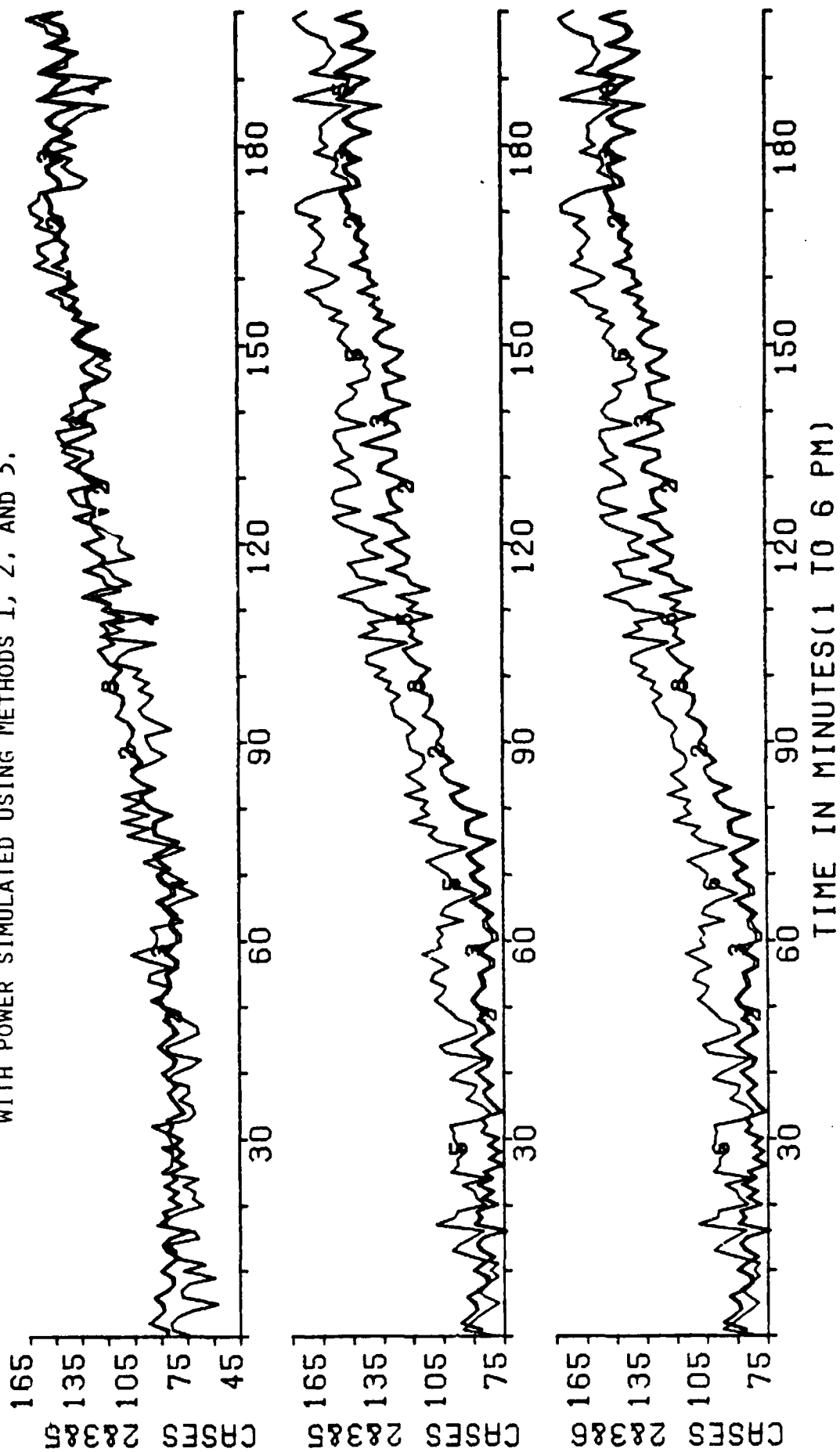shutdown may not always be predicted since the wind power prediction will always overestimate the actual wind array power level due to the spatial filtering caused by utilizing several reference wind measurement sites.

The error in predicting wind power will normally be approximately 20% even when no storm related events occur. This wind power prediction error is associated with error in predicting wind speed at several sites in the array and the error due to use of only a few wind prediction sites to simulate power from the large number of wind turbines in the array. If the wind power prediction error was 2% or less as it is for predicting load power variation in a utility, this wind power prediction error could be neglected. The wind power under open loop control, where the wind turbine array power output is not controlled, is considered as negative load. The wind array power produced under open loop control reduces the load power in a utility that must be served by non-wind generating units and is not controlled just as load is not controlled and thus acts as negative load. The large error in predicting wind power would thus increases the effective error in predicting the load power that must be served by conventional generation. Operating reserve, spinning reserve, unloadable generation reserve, and load following reserve levels within unit commitment schedules, that determine when generating units must be brought on-line or shutdown, must be adjusted based on the magnitude of the wind power prediction error. Modified generation control methods must be employed to compensate for the large cyclic wind power variations that comprise a portion of this wind power prediction error. Modified unit commitment and generation control methods that utilize this wind power prediction error are discussed in Section 2 of this report.

Methods for estimating or predicting the error in wind power prediction are discussed in this section. A band on the wind power prediction is required since sufficient spinning reserve on conventional generation is required to cover cases where the predicted wind generation is greater than actual wind power generation and sufficient unloadable generation reserve is required when predicted wind generation is less than actual wind power generation.

The first method to estimate wind speed prediction error is based on the assumption that the wind speed prediction error is time invariant and is normally distributed. If the wind speed prediction error $W(t) - \hat{W}(t)$ is time

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invariant and normally distributed, with zero mean and standard deviation $_w$, then

$$P\{\ \hat{W}(t) - W(t)\ < 3\sigma_w\} \approx .99$$

A method for estimating wind power prediction error given the wind speed is normally distributed and the correlation between wind speeds records at different wind turbine sites is given in [2] and is discussed in Section 3 of this report. This method of predicting when power variation could be applied based on the following tests showing wind speed prediction error is time invariant and normally disturbed.

The actual wind speed and predicted wind speed records for sites 21, 22, 24, and 26 during the movement of a front from 1 - 6 p.m. on May 2, 1979 is given in Figure 34 and 35. The actual wind speed records 23 and 25, used to predict wind speeds records at sites 21, 22, 24, and 26 are filtered using a 10 minute moving average filter in Figure 34 and by a 2 minute moving average filter in Figure 35. The rms errors for all sites is given in Table 12 for both the 2 minute and 10 minute filtered records. The errors decrease as the filtering interval increases. This result is confirmed by noting the error magnitude between the actual and predicted wind speed records for the 10 minute and 2 minute filtered records in Figures 34 and 35, respectively. The actual wind speed prediction error is plotted in Figure 36 and shows the error has zero mean and appears time invariant. Thus, these two assumptions required for estimating a band around the predicted wind speed $\hat{W}(t)$, which will contain $W(t)$

$$\hat{W}(t) + 3\sigma_w \leq W(t) \leq \hat{W}(t) + 3\sigma_w$$

are satisfied. A statistical hypothesis test, that determines whether the wind speed error sampled every minute is normally distribution, was applied. The hypothesis test was applied to each SESAME array where wind speed prediction was attempted. The hypothesis that the wind speed prediction error is normal was accepted using a threshold on differences between the distribution of the sampled error and actual normal distribution. This threshold was selected so that 95% of such decisions would be correct and 5% of such decisions would be incorrect. The results of the statistical tests on every wind speed prediction site is given in Table 13 for both the 10 minute filtered and the 2 minute filtered records.

The wind speed prediction errors was decided to be normal in 16 of the 25 sites when the 2 minute filtered data was tested for normality. Ten of 25 sites were decided to be normal when the 10 minute moving average filtered data was used. The filtering eliminates and distorts the error variations causing more sites to reject the normality hypothesis. Sites 27, 17, 16, 21, 19, and 6, where the normality hypothesis was rejected, are located at the eastern and western of the SESAME array where wind speed prediction using sites 23 and 32 was not as effective. Sites 8, and 12 had site specific effects that could have caused the error to be non-normal, which explains why the normality hypothesis was rejected for these sites.

The results on this May 2nd 1-6 p.m. data were very encouraging since the wind speed prediction error was shown to be normal, zero mean, and time

FIGURE 54. COMPARISON OF ACTUAL AND PREDICTED WIND SPEED AT SITES 21, 22, 24, AND 26
USING 10 MINUTES MOVING AVERAGE FILTERED MEASUREMENT RECORDS.

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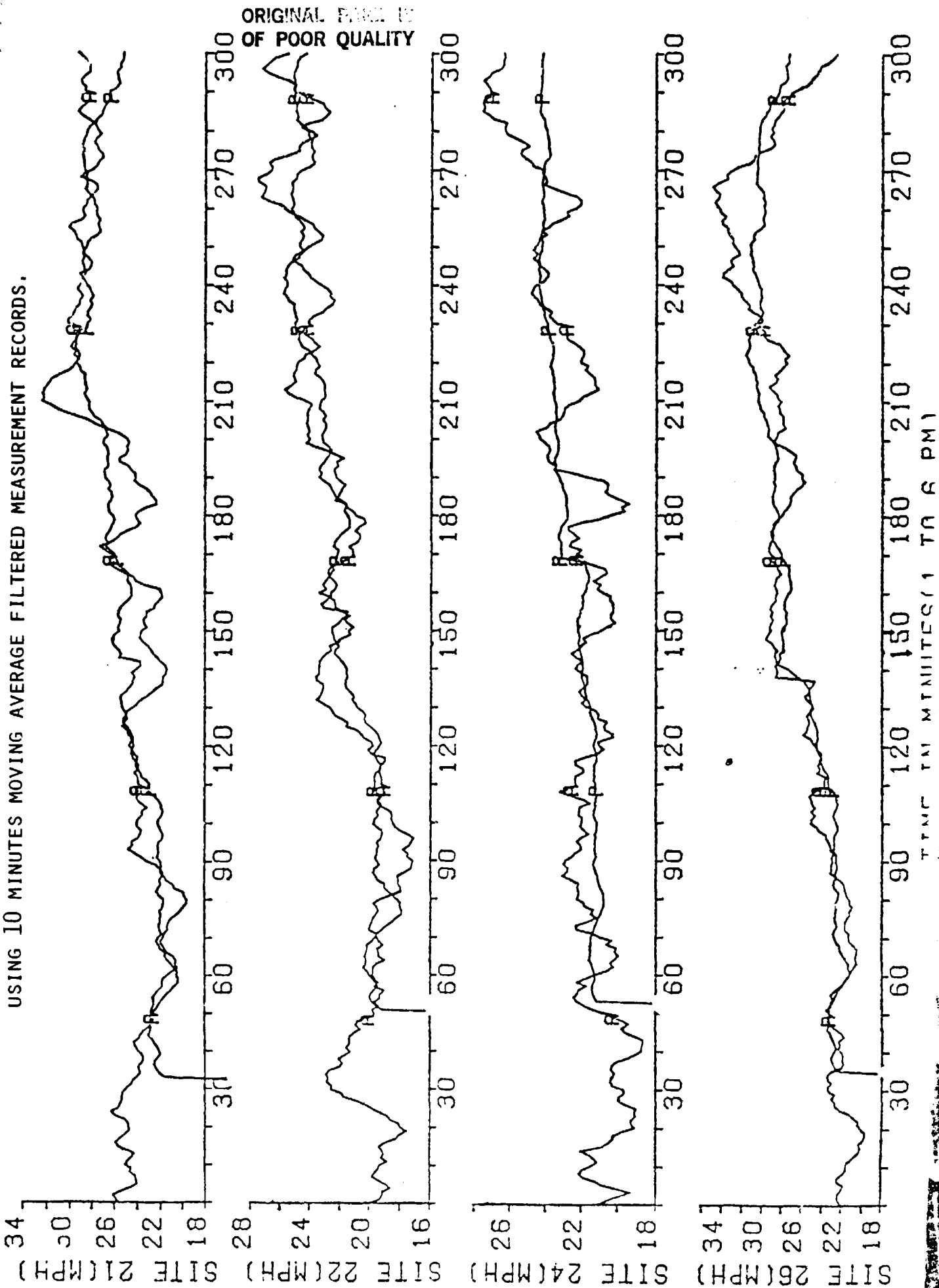
FIGURE 35. COMPARISON OF ACTUAL AND PREDICTED WIND SPEED AT SITES 21, 22, 24, 26,
2 MINUTE MOVING AVERAGE FILTERED RECORDS.

TIME IN MINUTES(1 TO 6 PM)

155
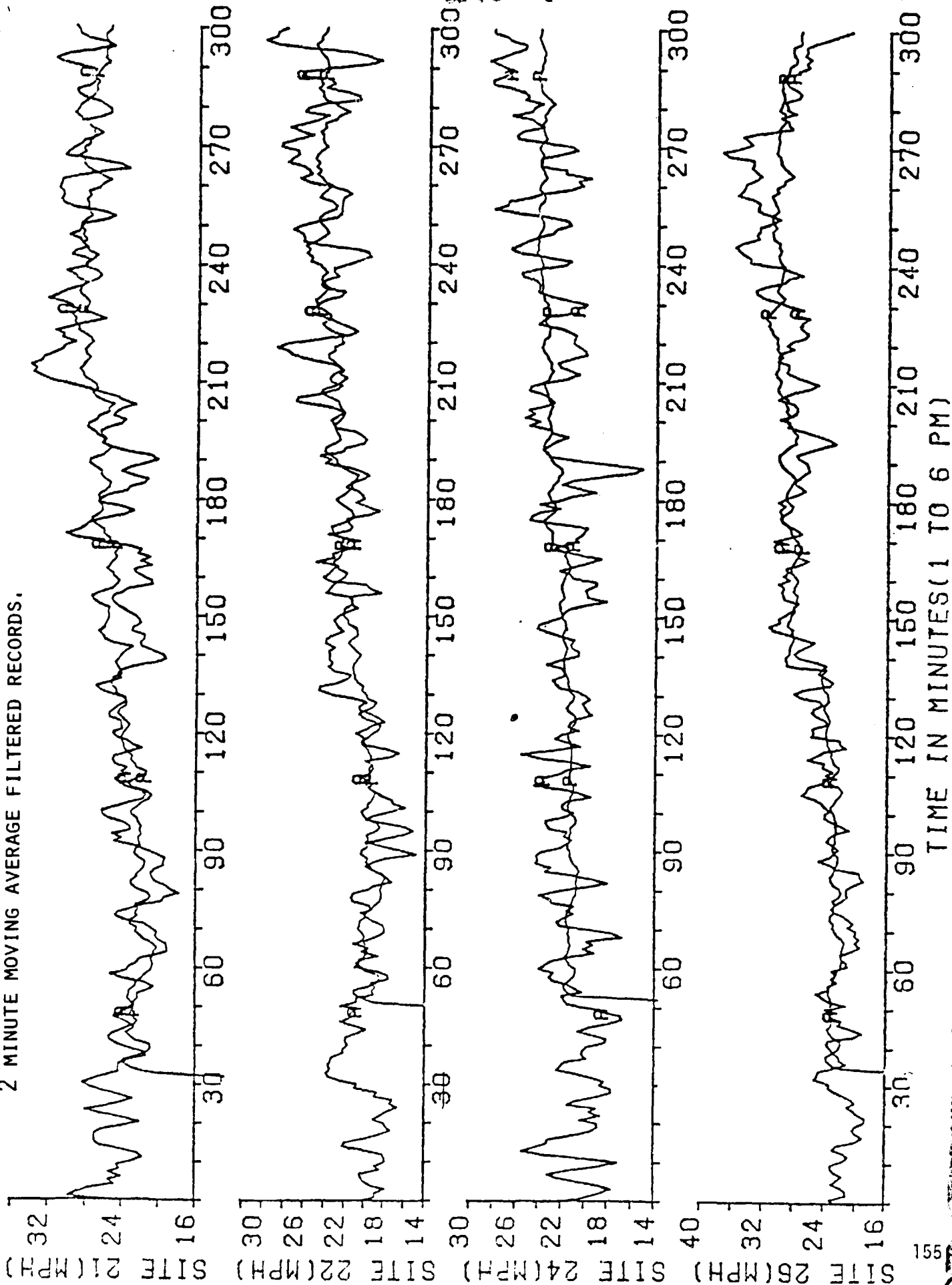
TABLE 12. TABLE OF PREDICTION ERRORS FOR 2 MINUTE AND 10 MINUTE
FILTERED (1-6 P.M.) DATA OF MAY 2, 1979 WITH SITES
23 AND 25 AS REFERENCE.

SITE NO.	ERROR (MPH) 2 MINUTE FILTERED	ERROR (MPH) 10 MINUTE FILTERED
1	3.151	2.366
2	3.126	2.252
3	2.225	1.515
4	3.408	2.500
5	2.968	2.163
6	2.465	1.672
7	2.525	1.796
8	2.466	1.516
9	2.898	2.301
10	2.840	2.127
11	1.919	1.087
12	2.640	1.624
13	2.673	2.063
14	2.163	1.199
15	2.068	1.351
16	2.682	1.659
17	2.056	1.314
18	2.098	1.333
19	2.975	1.686
20	2.041	1.302
21	2.460	1.753
22	2.185	1.296
24	2.041	1.372
26	2.363	1.838
27	2.593	1.827

FIGURE 36. ERROR IN WIND SPEED PREDICTION AT SITES 21, 22, 24, AND 26.

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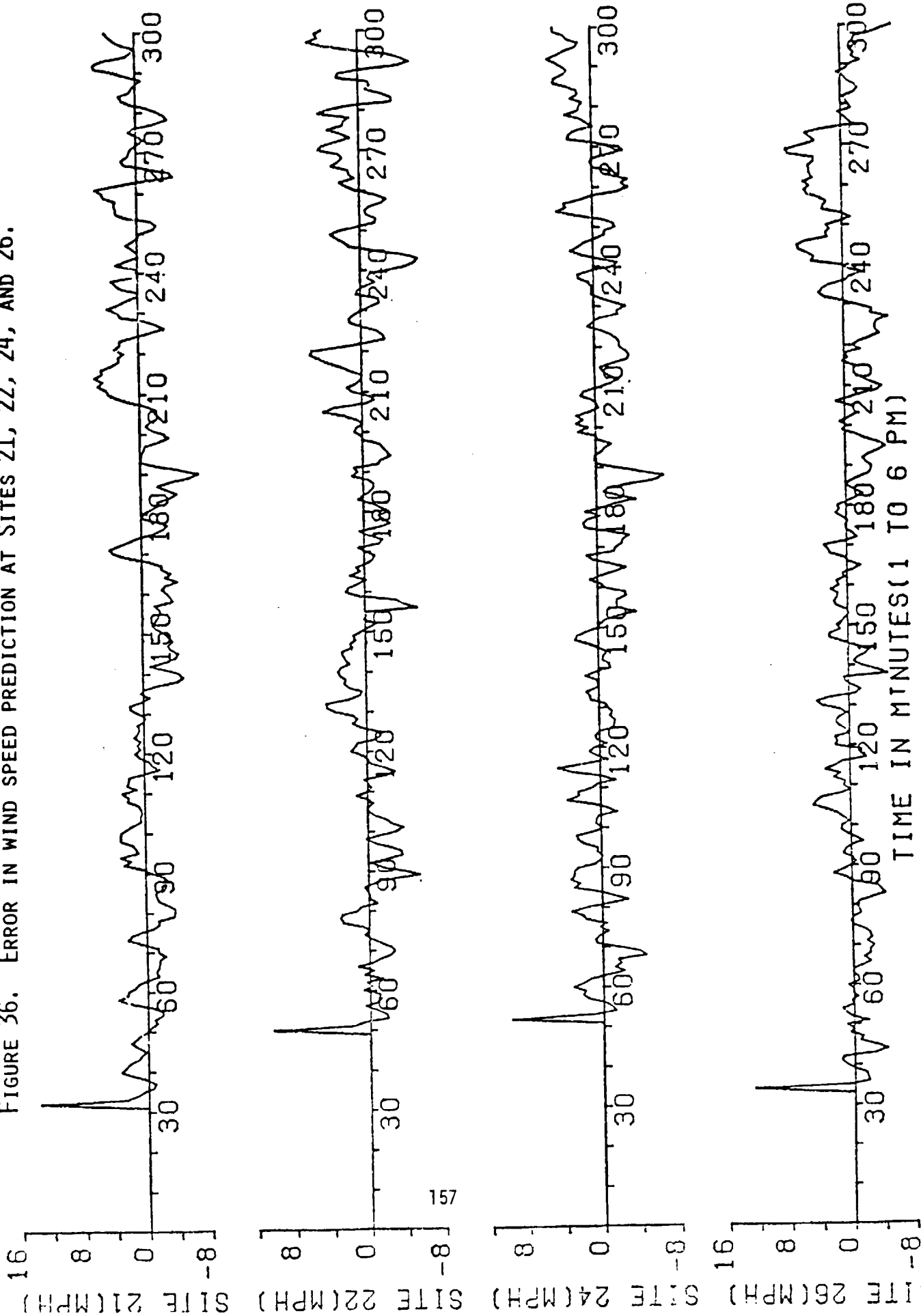
TABLE 13. RESULTS OF HYPOTHESIS TEST FOR PREDICTION ERROR AT 2 AND 10 MINUTE FILTERED 1-6 P.M., DATA.SET OF MAY 2, 1979.

SITE NO.	10 MINUTE FILTERED	2 MINUTE FILTERED
1	reject	reject
2	reject	accept
3	reject	accept
4	accept	accept
5	reject	accept
6	reject	reject
7	reject	accept
8	reject	reject
9	reject	accept
10	reject	accept
11	accept	accept
12	reject	reject
13	accept	accept
14	reject	reject
15	accept	accept
16	reject	reject
17	reject	reject
18	accept	accept
19	accept	reject
20	accept	accept
21	reject	reject
22	accept	accept
24	accept	accept
26	accept	accept
27	reject	reject

invariant when the wind speed prediction is being successfully accomplished. The error band on the actual wind speed is plotted along with the actual wind speed in Figure 37. It clearly indicates the actual wind remains in the band

$$\hat{W}(t) = 3\sigma_W \leq W(t) \leq \hat{W}(t) + 3\sigma_W$$

and that the band is not too small or large based on the fluctuations of W(t) within the band.

This method of estimating wind speed prediction error was retested for the wind speed prediction for wind records taken from 3 to 10 p.m. on May 2nd. These wind speed records contained severe cyclic storm induced wind variation. Reference sites 7, 9, and 11 were chosen as references since they did not contain the storm induced variations. Using reference sites without storm induced cyclic wind variation was found to much more accurately predict the trend change in wind speed associated with a storm front. Since the cyclic storm induced variations are not correlated between sites due to their time varying characteristics, no effort is made to predict these variations when reference sites are chosen so that they do not contain such variations. The wind speed prediction error estimation procedure should hopefully be capable of estimating the magnitude of these variations.

The error between the actual and predicted wind speeds for the sites where wind speed was predicted on the 3 to 10 p.m. May 2, 1979 wind record using references 7, 9, and 11 are given in Table 14. The errors are considerably larger due to the large cyclic variations due to the storm that are not predicted. The error magnitude was once again smaller if the 10 minute moving average filter rather than a 2 minute moving average filter is used to smooth the actual wind speed at each site and the reference wind speed records used to produce the predicted wind speed records. The hypothesis test was again applied to determine if the error between the actual and predicted wind speed records at each site was normally distributed. The hypothesis given in Table 15 that the error was normally distributed was accepted on only 7 of 24 sites for both the 2 minute and 10 minute moving average filtered records. The sites where the hypothesis was accepted were generally close to the reference sites. The large cyclic variation due to the storm can be seen in Figure 38 where the actual wind speed record W(t) and the upper W(t) + $3\sigma_W$ and lower W(t) − $3\sigma_W$ limit are plotted for sites 22-25. Note that the cyclic variation that occurs between 300 and 380 minutes are quite different in shape and magnitude at these different sites. Thus, the period of the cyclic variation due to the storm was cut out of the wind speed record for each site and the hypothesis test for normality was performed again. The results in Table 16 show that several additional sites are now determined to have normally distributed errors as shown in Figure 39. Results are given only at the sites which were in the direction of motion of the meteorological event propagation since accurate wind speed prediction is only accomplished at these sites. Note that the normality hypothesis was rejected at 11/14 sites before the storm related variation was eliminated from the records and rejected at only 8/14 when the storm related variation was eliminated. These results indicate that the variaton not directly associated with the storm in a storm front was very often normally distributed even if the specific storm induced variation was not normally distributed.

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FIGURE 37. COMPARISON OF ACTUAL WITH PREDICTED WIND SPEED PLUS AND MINUS A THREE STANDARD DEVIATION BAND FOR A FRONT.
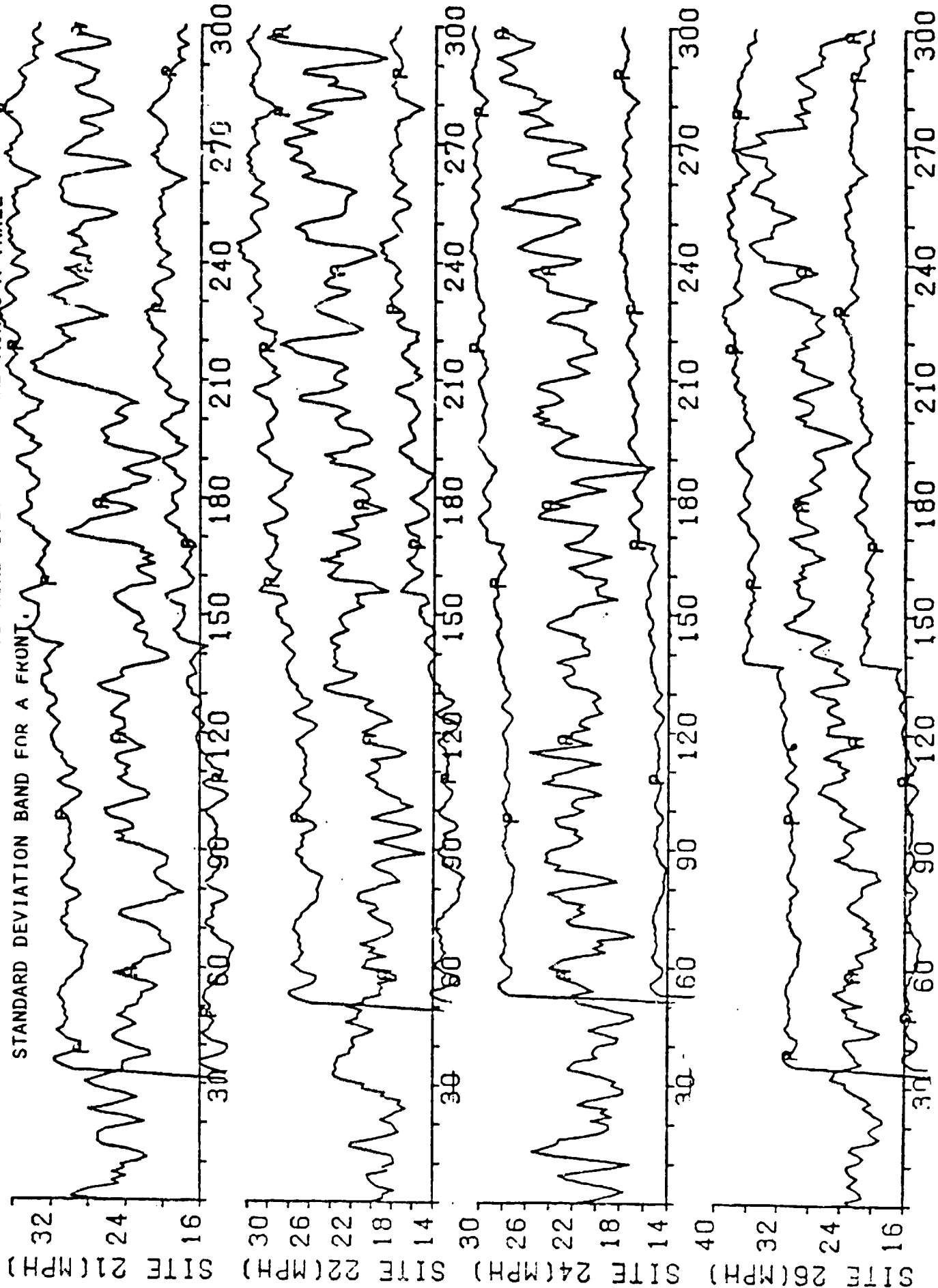
TABLE 14. TABLE OF PREDICTION ERRORS OF 2 AND 10 MINUTE FILTERED
3-10 P.M., DATA SET OF MAY 2, 1979.

SITE NO.	ERROR WITH 2 MINUTE FILTERED DATA SET (MPH)	ERROR WITH 10 MINUTE FILTERED DATA SET (MPH)
1	3.88	3.24
2	3.96	3.12
3	2.38	1.67
4	5.37	4.15
5	3.42	2.34
6	4.05	3.01
8	2.81	1.71
10	4.63	3.93
12	5.29	4.32
13	4.18	3.16
14	4.22	2.37
15	3.74	2.52
16	4.22	3.22
17	5.70	4.63
18	4.45	3.72
19	3.64	2.92
20	3.27	2.64
21	5.02	4.43
22	5.18	3.69
23	2.79	2.01
24	5.54	4.63
25	5.17	4.05
26	4.94	3.30
27	2.36	3.43

TABLE 15. RESULTS OF HYPOTHESIS TEST FOR THE PREDICTION ERROR AT
2 AND 10 MINUTE FILTERED DATA OF 3-10 P.M. OF MAY 4, 1979,
WITH SITES 7, 9, AND 11 AS REFERENCES.

SITE NO.	10 MINUTE FILTERED	2 MINUTE FILTERED
1	accept	accept
2	accept	reject
3	accept	reject
4	reject	reject
5	accept	reject
6	accept	accept
8	reject	reject
10	reject	reject
12	reject	reject
13	reject	accept
14	accept	reject
15	reject	reject
16	reject	accept
17	reject	reject
18	reject	reject
19	reject	reject
20	accept	accept
21	reject	reject
22	reject	reject
23	reject	reject
24	reject	reject
25	reject	reject
26	reject	accept
27	reject	accept

FIGURE 38. COMPARISON OF ACTUAL WITH PREDICTED WITH PLUS OR MINUS THREE STANDARD DEVIATION BAND FOR A STORM FRONT.

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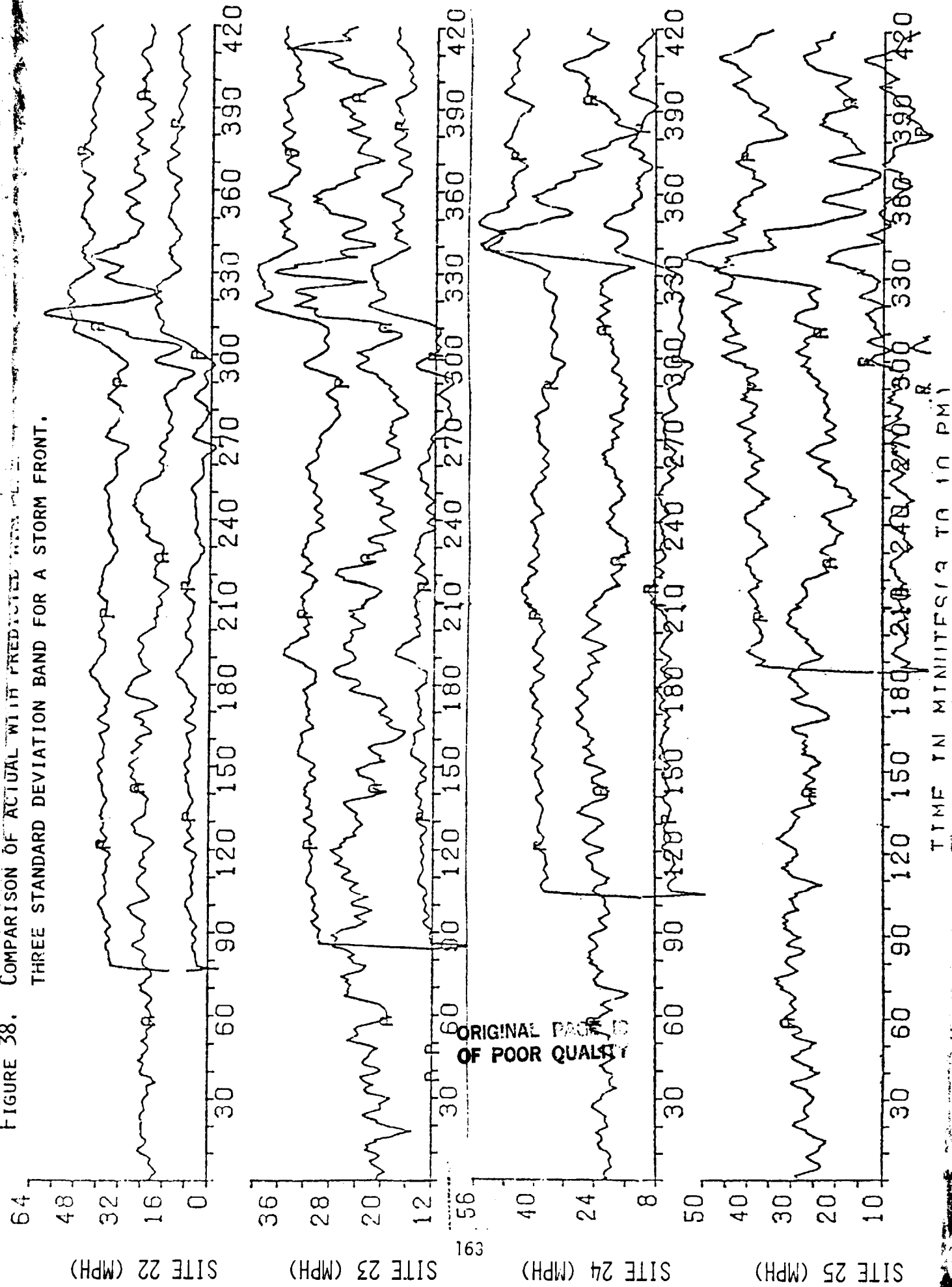
TABLE 16. RESULTS OF HYPOTHESIS FOR THE PREDICTION ERROR AT 2 AND 10 MINUTE FILTERED DATA FOR MAY 2, 1979, WHEN THE PERIOD OF THE STORM (7:00 - 8:30) IS DELETED.

SITE NO.	10 MINUTE FILTERED	2 MINUTE FILTERED
1	reject	accept
2	accept	reject
3	accept	reject
4	reject	accept
5	accept	reject
6	accept	reject
8	reject	reject
10	reject	reject
12	reject	reject
13	reject	reject
14	accept	accept
15	accept	accept
16	reject	reject
17	reject	reject
18	reject	reject(accept)
19	reject	reject
20	accept	accept
21	reject	reject
22	reject	accept
23	reject	reject
24	reject	reject
25	reject	accept
26	reject	reject
27	reject	reject

FIGURE 39. MAP COMPARING WHERE THE TEST OF HYPOTHESIS IS ACCEPTED AND REJECTED FOR THE CASE WHERE THE ENTIRE RECORD IS USED AND FOR THE CASE WHERE THE STORM IS REMOVED FROM THE RECORD. −/†

− test performed with storm retained in predicted and actual wind speed records.

† test performed with storm removed from predicted and actual wind speed records.

A − accept hypothesis

R − reject hypothesis

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The wind speed $\pm\sigma_w$ error was so large when the storm was present that the predicted wind power lower limit based on the estimated wind speed lower limit would be zero. The wind turbine array would be predicted to be shutdown during almost the entire interval that storm front was present using the lower limit $\hat{W}(t) - 3\sigma_w$. The wind power based on the upper limit of predicted wind speed $\hat{W}(t) + 3\sigma_w$ would indicate that the array power would be at the total wind array generation capacity. The actual simulated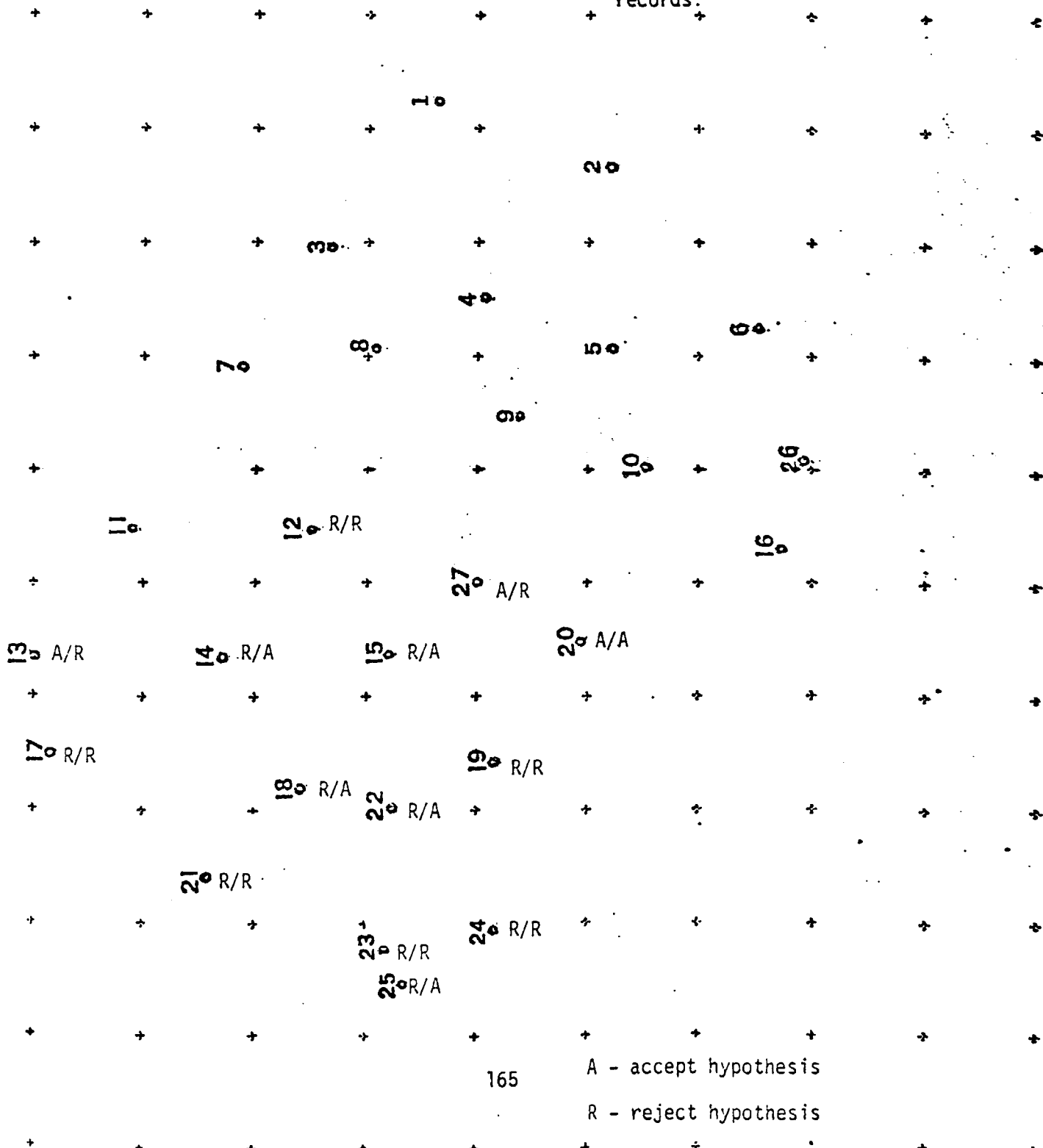 power for such a record on an individual wind turbine would continually cycle between rated capacity and shutdown, as shown in Figure 40 for sites 2 and 7. The wind power from an array of 81 wind turbines at sites 2 and 7 is shown in Figure 41. The power out of the 81 wind turbine array would also cycle from rated array capacity to very small levels of power several times as the storm passed through the array. Some utilities may attempt to keep the wind turbine array operating during such storm induced variations. However, the utility must keep the capacity of the array in spinning reserve during the entire period of the storm since spinning reserve is based on the lower limit $W(t) - 3\sigma_w$. Thus, the utility would not anticipate power from the array at any time in the scheduling of units using the modified unit commitment procedures discussed in Section 2. The cyclic power variation out of the array during periods of storm induced variation would be compensated by fast responding units under feedforward control. The cyclic power variation that could not be handled by the response capability of these fast responding units would be clipped by the closed loop coordinated blade pitch control or the wind turbines in the array. The coordinated blade pitch control would not allow the wind generation level out of the array to significantly exceed the magnitude of the generation change out of the fast responding units under feedforward control so that steam generating units and the system AGC would not have to respond to these cyclic storm induced wind power variations. The elimination of the need to compensate for wind power fluctuation using regulating units under control would increase fuel economy of these units, reduce maintenance on these units, and reduce loss of unit life on these units.

A second method of estimating wind power prediction error directly rather than estimating wind speed prediction error and then computing the wind power prediction error is proposed. This method does not need to determine the wind speed prediction error statistics and does not require determining the correlation between wind turbine sites. Moreover, this method does not require that the wind power prediction error be normal or time invariant.

The wind power prediction error at time minutes ahead is predicted using an average of the error in predicting wind power over the previous K minutes

$$\varepsilon(t + N) = C_{max} \{\frac{1}{K} \sum_{k=1}^{K} |P(t - k) - \hat{P}(t - k)|; \ 0.1 \ P(t)\} \qquad (7.1)$$

if the error is greater than ten percent of the power actually produced by the array at time t. The predicted error $\varepsilon(t + N)$ is never allowed to become smaller than .1 P(t) since the short term average error
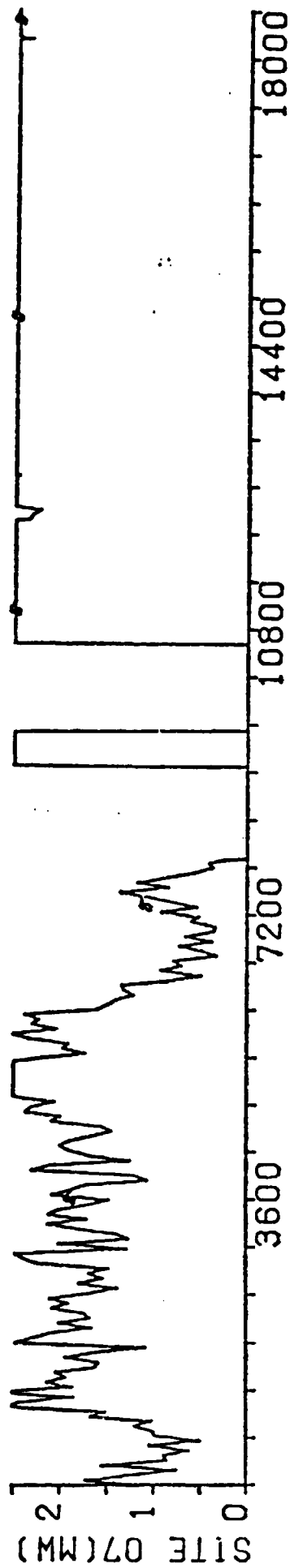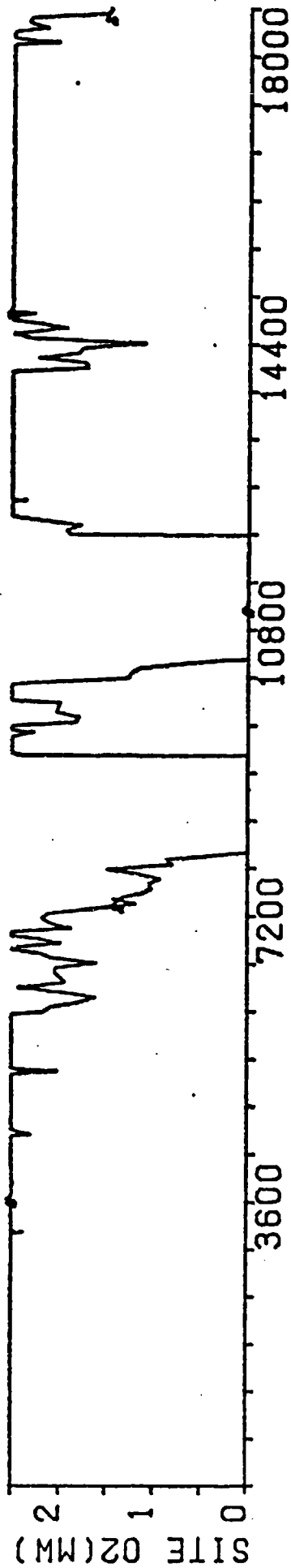
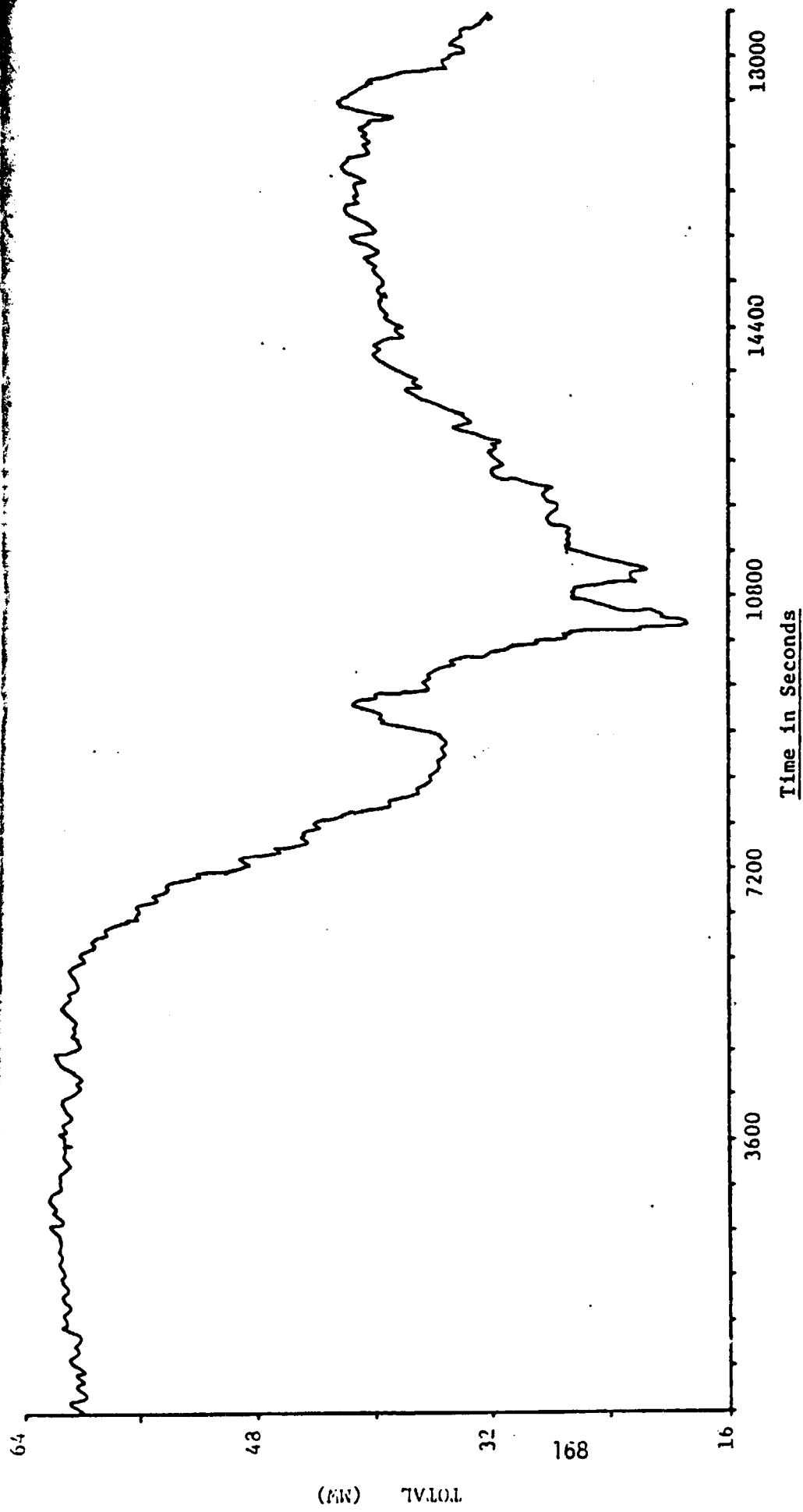FIGURE 40. POWER FROM A SINGLE WIND TURBINE AT SITE 2 AND 7.

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FIGURE 41. POWER FROM AN 81 WIND TURBINE ARRAY

$$\frac{1}{K} \sum_{k=1}^{K} \left| P(t - K) - \hat{P}(t - k) \right| \tag{7.2}$$

between the actual $P(t - k)$ and predicted $\hat{P}(t - k)$ wind array power may become small over certain periods and will not certainly reflect the expected error at $t + N$. The constant C is chosen as 1 but can range from 0 - 3 depending on the forecasted wind conditions that are expected to effect the wind array at $t + N$. In some cases, the wind power prediction error is expected to increase and C is selected to be greater than one if a storm is anticipated to pass through the array. In other cases, the error (7.2) may at present be large and is expected to decrease as the front or storm passes and C is selected to be less than one.

This method of predicting wind power prediction error does not assume the error is time invariant but is slowly time varying. The error band based on this error

$$\hat{P}(t + N) - \epsilon(t + N) \leq P(t + N) \leq \hat{P}(t + N) + \epsilon(t + N) \tag{7.3}$$

does not require that the error to be normal and can be adjusted using C so that the future error need not be maintained at C = 3 as in the first method but can be set at values between $0 \leq C \leq 3$ depending on the expected changes in wind power prediction error. This method is an on-line procedure and predicts the error N minutes ahead rather than using error computed off line using the entire actual and predicted. This second method is thus far superior to the first method discussed earlier.

This second wind power prediction error prediction method was tested on the actual and predicted wind power records at sites 1-5 for the period 1-6 p.m. on May 2, 1979. Reference sites 23 and 25 were used to produce the wind power predicted at sites 1-5.

The wind prediction power error predicted 30 minutes in advance based on a 15 minute average of the wind power prediction error is shown in Figure 42 for site 1-5. The band (7.3) generally contain the actual wind power $P(t + N)$. The band for site 1 and site 5 has cyclic variation due to the fact that the error $P(t) - \hat{P}(t)$ has large cyclic variations. Since $\epsilon(t + N)$ never decreases below $0.1 P(t)$ the error $\epsilon(t + N)$ depend on the average

$$\frac{1}{K} \sum_{k=1}^{K} \left| P(t - k) - \hat{P}(t - k) \right| >> 0.1 P(t)$$

producing large values of $\epsilon(t + N)$ that may or may not reflect the actual error $P(t + N) - \hat{P}(t + N)$ that occurs at $t + N$.

A K = 30 minute average of the error prior to t rather than a K = 10 minute average reduces and smoothes the large cyclic variations in $\epsilon(t + N)$ as shown in Figure 43. The N = 30 minute prediction interval is utilized for the results in both Figure 42 and 43. Other prediction intervals were chosen and the accuracy of the prediction in terms of period out of the band and the rms error during this period out of the band were not affected. Thus, a N = 30 minute prediction interval based on a K = 30 minute average of previous error

FIGURE 42. PREDICTED ERROR BAND AROUND THE ACTUAL POWER WHERE THE ERROR IS PREDICTED 30 MINUTES AHEAD BASED ON A 10 MINUTE AVERAGE.
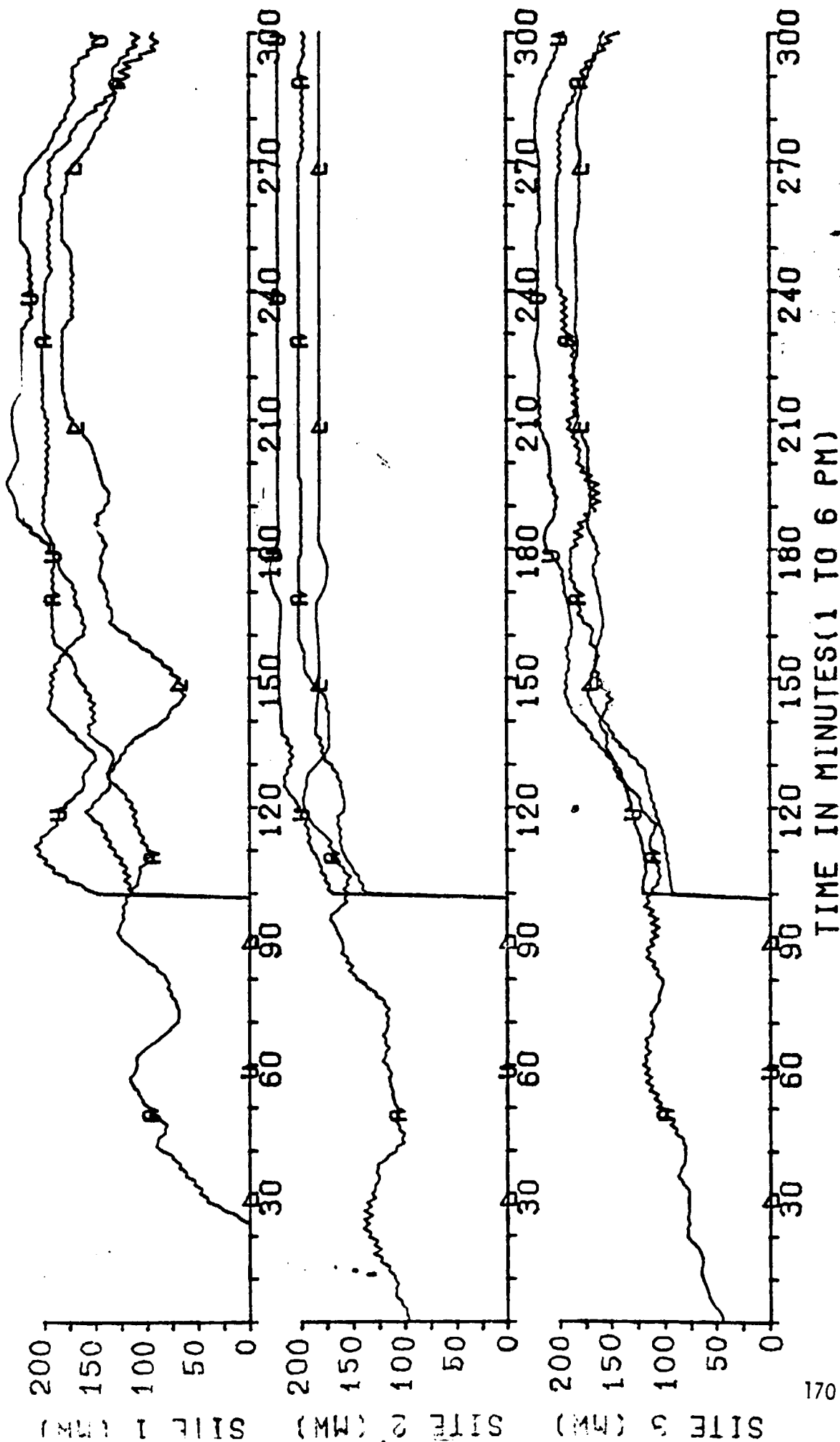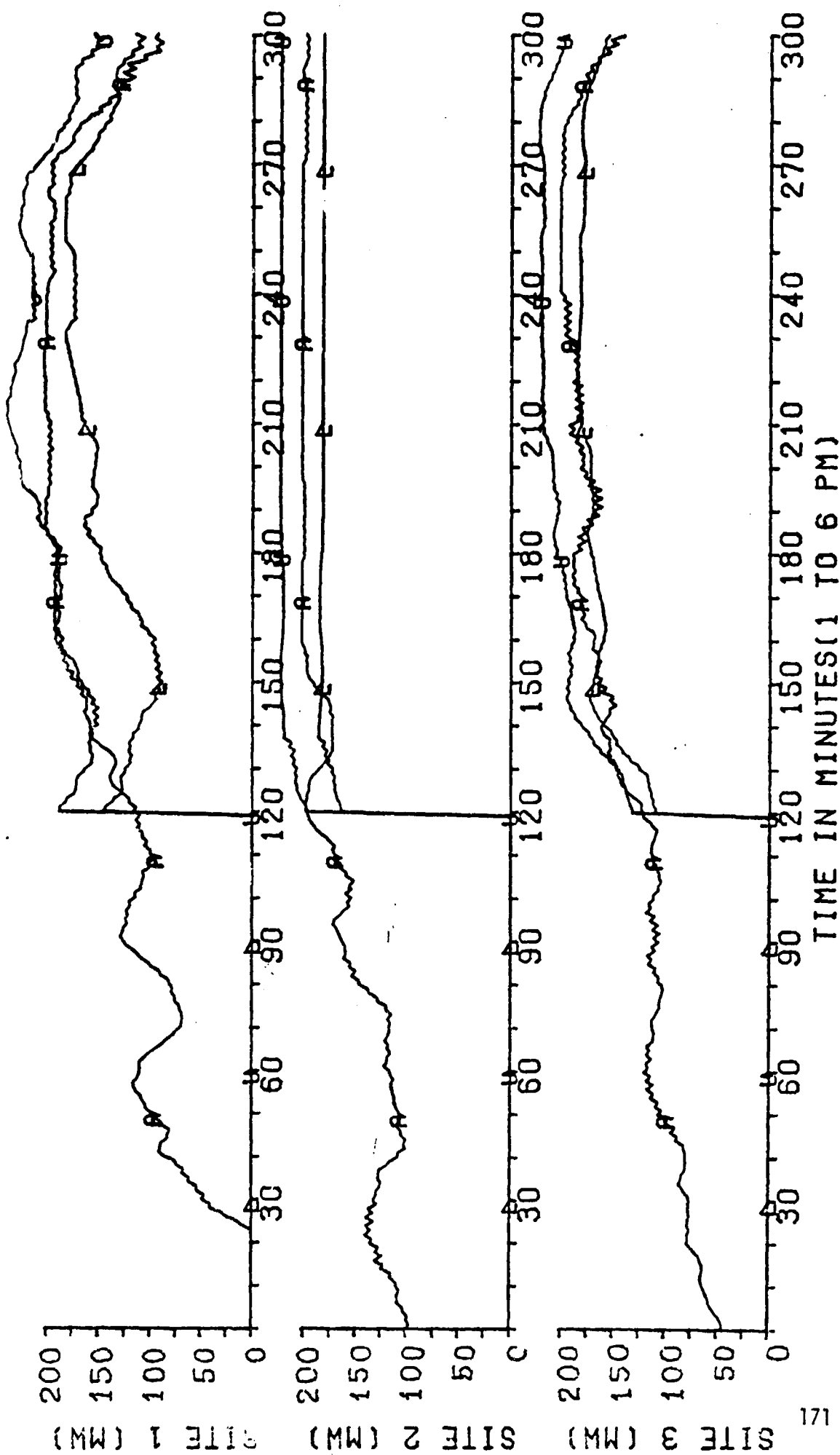
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FIGURE 43. PREDICTED ERROR BAND AROUND THE ACTUAL POWER WHERE THE ERROR IS PREDICTED 30 MINUTES AHEAD BASED ON A 30 MINUTE AVERAGE.

appeared to produce the best results in terms or predicting error into the future and minimizing the cyclic variation in error observed when the average of this error was small.

SECTION 8

CONCLUSIONS AND FUTURE RESEARCH

The purpose of the research is the development of:

(1) a modified unit commitment;

(2) a modified generation control;

(3) a trend wind power predictor required by both the modified unit commitment and generation control procedures developed;

(4) a wind power error predictor required by both the modified unit commitment and generation control procedures

These four developments permit one to answer the following two questions which are to be addressed by the research to be conducted within the Federal Winds Energy Research Plan: 1985-1990

(1) what is the magnitude of the capacity credit that can be assigned to wind energy produced by large arrays based on methods for setting and meeting the load following and operating reserve requirements within a utility's unit commitment. This magnitude of the capacity credit assigned to wind will determine the breakeven point in terms of 30 year levelized cost in $/KWH that wind energy technology must achieve to warrant large scale implementation by utilities.

(2) Develop a generation control strategy that minimizes the impact of large rapid changes in wind array generation that is caused by "rotor synchronization" [1, A-3. III-20] of all wind turbines in the array for large meteorological event wind speed changes. The utility's steam turbine generation is slow responding and cannot compensate for these large rapid wind generation changes. Attempting to force these units to compensate for these large wind generation changes would cause cycling in these units that would expend significant fuel, increase maintenance, and possibly reduce unit reliability and lifetime. A modified generation control is proposed in this research based on an hour ahead prediction of wind power change. This modified generation control would utilize these slow responding large steam turbine units up to a limit imposed by the utility; fast responding diesels, hydros and gas turbines that are not presently effectively controlled, and wind turbine array control of wind power output as a last resort.

This modified generation control strategy has been developed to allow the utility to determine the level of participation its large steam turbine units should have in compensating for large wind generation changes. This modified generation control was designed so that quick pickup units provide the principal compensation for the large wind change. The modified quarter hour updated unit commitment strategy would continually unload these quick pickup units and replace them with standby economic, peaking, and regulating

units. The purpose of maintaining quick pickup generation in spinning
reserve is to maintain adequate spinning reserve and load following margins
to compensate for large drops in wind generation. If the wind generation
increase exceeds the allocated combination of the response capability of
large steam turbines under automatic generation control and the level of
quick pickup generation connected and loaded (that could be unloaded and
disconnected in 15 minutes by the feedforward generation control to compen-
sate for the wind generation increase), the closed loop wind turbines array
control would reduce the wind generation rate of change to the level the AGC
and feedforward control could handle. For wind generation decreases, the
AGC would again compensate for the wind generation change up to the
capability allocated to tracking wind generation change. The feedforward
control of quick pickup units would then be capable of connecting and fully
loading all quick pickup generation within the spinning reserve within
fifteen minutes to compensate for wind generation decrease. The quarter
hour unit commitment would schedule their connection and the feedforward
generation control would set the gain on their governor controls so that
they would be properly loaded. These quick pickup units, once connected,
would be controlled utilizing the area control error signal used for regu-
lating units under AGC. The participation factor on the quick pickup units
would be adjusted by the feedforward generation control to obtain the de-
sired generation change out of these quick pickup units and thereby prevent
units under AGC from exceeding the allocated response capability assigned to
compensating for wind generation. If the predicted wind generation decrease
is greater than the combined response capability of the feedforward genera-
tion control and the allocated response capability of the units under AGC,
then the closed loop array control attempts to build up a back off reserve
on the wind turbines by clipping wind generation below the level that would
otherwise be produced given the present wind speed at the particular time.
This back off reserve is utilized as a cu͞   so that when the predicted
drop in wind generation occurs it is not   �er than could be handled by AGC
and feedforward control within 15 minutes. The development of the back off
reserve is possible due to the hour ahead prediction interval and the fact
that the level of wind generation to be clipped is based on the maximum
predicted wind generation decrease (trend wind power minus the error in the
trend wind power prediciton) and not just the trend wind power change.

The following accomplishments of this research project are unique:

(1) the development of wind speed prediction for meteorological events
     and turbulence induced variation. Prediction of wind speed based on
     turbulence alone was performed in [2], but the magnitude of
     turbulence induced variation is so small compared to meteorological
     event variation that it does not require prediction to assure power
     system reliability and economy;

(2) the development of a method for predicting the error in the wind
     power predictor;

(3) the development of wind power prediction methods. The assessment of
     different wind power prediction methods, the effect of increasing
     the number of wind power prediction sites in the array, the proper
     siting of these prediction sites, and the proper simulation method

for producing array power variation from several wind speed prediciton sites were all investigated in the research;

(4) investigation of a modified unit commitment procedure that would greatly increase the capacity credit given to wind generation. Without trend wind power prediction and wind power error prediction, a utility would not be able to connect or disconnect nonwind generation in proportion to predicted wind generation increase or decrease respectively. Thus, although one could achieve a capacity credit based on LOLP calculations, the operation of the utility effectively prevented wind generation from serving any load since no nonwind generation capacity is displaced by wind generation. The modified unit commitment procedure proposed would increase load following and spinning reserve proportional to the magnitude of the wind power prediction error. The magnitude of the spinning reserve increase at any time, which is proportional to wind power prediction error at that time, is the amount of the wind generation that is not allowed to be counted as meeting load due to the lack of perfect prediction of wind power variation. Wind power prediction thus permits one to provide capacity credit for wind and improvements in wind power prediction accuracy increase the capacity credit given to wind array power variation. The research performed in this project is the only published research on modified unit commitment methods that can utilize wind power prediction to modify the 24 hour unit commitment based on predicted wind generation changes.

(5) the development of a generation control strategy based on the one developed in [8] but that utilizes both the trend wind power predictor and the wind power prediction error predictor for both meteorological event and turbulence induced variation. The generation control utilizes the control philosophy in the priority use of automatic generation control, feedforward control, and array control but incorporates the effects of predicting meteorological events and the effects of wind array power prediction error. The generation control strategy proposed would satisfy utility reliability requirements while simultaneously assuring economic operation. Furthermore, the proposed generation control would limit the cycling on large steam units that would increase fuel costs, increase forced outages, and possibly reduce unit lifetime.

The methodology has not been integrated into an individual package. Thus, the capabilities and performances of the modified unit commitment and modified generation control can not be fully quantified and validated and should be evaluated in a future research project.

These four developments of this research project are now briefly reviewed to point out the conclusions reached and contributions obtained.

A modified unit commitment procedure is developed that is composed of a:

(1) 24 hour ahead unit commitment that schedules connection and disconnection of non wind and wind generation based on a 24 hour

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ahead load forecast and a 24 ahead forecast of diurnal wind power variation;

(2) quarter hour updated unit commitment that schedules connection and disconnection of quick pickup units and standby economic, peaking, and regulating units. This quarter hour updated unit commitment depends on a one or more hour ahead prediction of trend wind power variaiton as well as a half hour or more ahead prediction error.

Methods of setting the operating reserve, spinning reserve, unloadable generation reserve, and load following reserve for the 24 hour ahead unit commitment are established. The operating reserve is based on a LOLP calculation assuming the wind turbine array experiences no meteorological events and the forecasted diurnal wind power variation is modeled as a load duration curve within the normal procedures used to calculate operating reserve. Spinning reserve, unloadable generation reserve, and load following reserve are developed based on Equations (1-3) where the wind power prediction is the diurnal wind power variation and the wind power prediction error $Q_w^+(k)$. $Q_w^-(k)$ are assumed to be small. The 24 hour unit commitment schedule is intended to maximize the economic operation of the utility without consideration of the impacts of meteorological events that can severly affect operating reliability and economy. Since the effects of meteorological events and sometimes their occurrence, time of arrival, and time of departure can't be accurately predicted 24 hours ahead, the 24 hour ahead schedule neglects their effects and schedules the system to maximize economic operation and maximize the capacity credit available to wind generation capacity.

The quarter hour updated unit commitment would schedule connection of quick pickup units and a set of economic, peaking, and regulating units on standby that would assure the operating reliability of the utility for the large meteorogical event induced wind power variations. This quarter hour updated unit commitment would obviously modify the most economical unit commitment schedule provided by the 24 hour unit commitment but only enough to insure operating reliability. Methods for setting operating reserve for the quarter hour unit commitment are discussed but no such method has been formally developed at this point. Methods for setting spinning reserve, unloadable generation reserve, and load following reserve for the quarter hour updated unit commitment are given that utilize the trend wind power predictor and the wind power prediction error predictor to determine $W_{k+j/4}$ $Q_w^+(k+j/4-1)$ and $Q_w^-(k+j/4-1)$. The constraints utilized by the quarter hour unit commitment in meeting their spinning reserve, unloadable generation reserve, and load following requirements are given in Equations 4-6. The constraints on minimum and maximum generation on a unit, and on minimum startup and shutdown periods for units are also discussed.

The quarter hour updated unit commitment attempts to maintain sufficient quick pickup generation in spinning reserve and load following reserve to respond to sudden wind generation decreases. Quick pickup units are unloaded and disconnected by the quarter hour unit commitment and replaced by standby economic and regulating units in order to increase spinning and load following reserve as well as to decrease fuel costs. Quick pickup generation is connected and loaded if wind generation decreases occur.

A trend wind power predictor was developed in this research project. The research in this project showed:

(1) time filtering wind speeds caused significant distortion of the maximum, minimum, and average values in wind speeds predicition and could introduce significant delays;

(2) time filtering is not required to determine meteogological event propagation direction, the reference groups used to predict wind speed at prediction sites in the wind array, or propagation delays between referenced and prediction sites. This is a change from the wind speed prediction method developed in [20];

(3) the reference measurement sites should encircle the wind turbine cluster at a distance of at least 100 miles away from all wind turbine clusters. Meteorological events can propagate at speeds between 0-100 mph and thus a 100 mile separation allows one or more hour ahead trend wind power prediction;

(4) the reference groups should not contain storm cell induced cyclic variation because such variation is site specific and time varying. Using reference sites with cyclic storm induced variation prevents prediction of the trend changes in wind speed that are associated with the storm front and can be predicted;

(5) the reference groups used for prediction should change when the wind shift associated with an incoming front first affects a particular cluster of wind turbines. The reference group should change from one that is in front of the wind array in the direction of propagation of the initial meteorological event to reference sites that are in front of the wind turbine array in the propagation direction of the incoming event.

(6) the use of several wind speed reference sites introduces a spatial filtering of wind speed variation associated with a meterological event. This spatial filtering associated with the wind speed prediction is shown to cause the predicted wind power variation to exceed the actual wind power produced by the array by as much as 10-20%;

(7) several wind prediction sites are required to produce accurate wind array power estimates. The error utilizing a single wind speed prediction site to simulate a 90 wind turbine array could be as large as 100% depending on the prediction site selected within that wind turbine array. The error could be reduced to 25% if three reference sites are used. The larger the number of prediction sites the smaller will be the effect of site specific effects and wind speed prediction errors of any prediction site. If the wind speed at each wind turbine is not predicted due to the computational burden, then one should select prediction sites so that each

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prediction site is geographically closest to an equal number of wind turbine sites. This method of siting wind prediction sites minimizes the site specific effects and error of any one wind prediction site on the total array power prediction;

(8) the study of five different methods of simulating wind array power variations indicates that there can be significant differences between the results obtained using different methods. These differences are minimized as the number of wind prediction sites increases. No one method of simulating wind array power variation will be most accurate for all wind conditions since the magnitude of the error and site specific variation at a wind prediction site will vary with the wind conditions. Since each simulation method minimizes effects of error at specific sites and accentuate error at other sites, no one simulation method can give the most accurate estimate of true wind array power variation for all wind conditions;

(9) the magnitude of the wind array power prediction error depends on the magnitude of the storm induced cyclic variation and turbulence induced wind power variation that can not be predicted using the trend wind power predictor. The error in the trend wind power predictor due to the spatial filtering in the wind speed predictor also contributes to wind array power prediction error. This wind power prediction error can be the magnitude of the capacity of the wind array during storms since the large cyclic variations can cause cycling between zero and rated array capacity. The error is large because the cyclic variation can not be predicted using this methodology. The wind power prediction error can be kept below 10% - 25% for other wind conditions if a sufficient number of wind power prediction sites are used to simulate the wind array power variation.

A wind power prediction error predictor was also developed in this research. The wind speed prediction error was shown to be a zero mean and normal at sites where wind speed prediction is successfully accomplished. The wind power prediction error was shown to be slowly time varying. Thus, a wind power error predictor was proposed that averages the absolute error between the actual array power output and the predicted array power over a 15 or 30 minute period and uses this error estimate to predict power 30 minutes ahead. This predicted error is not allowed to be less than 10% of the wind array power output since even though the error may become very small for a period of time it does reflect the error that can be expected to occur at some time in the future. This wind power prediction error predictor was thoroughly tested. The error band around the predicted array power was shown to effectively band the actual wind power variation.

There are three major research tasks that can be clearly identified based on the results of this research project:

(1) investigation of improved wind power prediction method,

(2) develop simulation and evaluation of the performance of the modified unit commitment and generation control,

. (3) a cost/benefit study of the wind prediction/modified generation control-unit commitment procedures.

The present research contract has shown that wind array power prediction can be performed with an accuracy fo 10-20% for non storm meteorological event conditions but may have errors of 100% of array capacity during storms. The wind array power prediction required wind speed prediction at several sites within the wind turbine array if the accuracy of the wind array power prediction error is to be minimized. Utilizing several wind prediction sites would increase the computational requirements. The computational requirement would increase directly proportional to the number of wind speed prediction sites used and increases the number of wind speed measurement sites. An increase in the number of reference wind measurement sites that encircle the array and increase in the number of prediction sites in the array linearly increases the cost of land, cost of towers, cost of sensors, cost of the data acquisition system, and the cost of the computer system required to implement the wind power prediction. Alternate methods of acquiring wind speed and direction at the reference and prediction sites might be investigated. Use of additional meteorological information such as pressure, temperature, radar for storm related information may increase the accuracy of the estimates of wind spe_ for non-storm meteorological events and permit accurate prediction of storm induced wind speed variation. This research is needed to further improve the accuracy of wind array power prediction for both storm and non-storm induced variation and reduce the cost of implementation of the wind power predictor.

The second research task is to develop a simulation program that can evaluate and further develop and refine the modified unit commitment and generation control strategy. The simulation program could then evaluate the performance of the modified unit commitment/generation control on several different types of utilities with different wind conditions as done in the General Electric study [8]. Additional utilities would be studied that did not carry such large load following and spinning reserve capability.

A computer program would be developed that would simulate both the modified unit commitment and generation control procedures developed in this research project. A program for computing the operating reserve for the quarter hour up-dated unit commitment operating reserve based on the procedure outlined in Section 2.3 would be developed. The modified unit commitment procedure would determine operating reserve, spinning reserve, unloadable generation, and load following requirements based on the trend wind power prediction and the wind power prediction error predictor. The modified unit commitment would include constraints on minimum and maximum generation level; minimum start-up and shutdown times; and operating reserve, spinning reserve, load following, and unloadable generation constraints.

The computer program for simulating the generation control would be based on the program developed earlier at Michigan State for evaluating the

performance of present automatic generation control in handling wind generation change. The program is similar to the program developed for EPRL. This computer program would determine whether AGC should solely handle the wind generation change, whether feed forward control of quick pickup generation is required, and finally whether closed loop array control of wind array power is required based on predicted trend wind power and the predicted error in trend wind power change. The feed forward generation control based on the area control error would be developed and tested. The closed loop array control for reducing wind power rate of change would be evaluated.

The objectives of this research task is to determine whether the modified unit commitment/generation control can

(1) maintain operating reliability,

(2) minimize the fuel and maintainance costs utilizing unit commitment and economic dispatch programs,

(3) maintain the impact of wind generation change on system AGC below the levels specified as part of the generation control procedure.

The third task is to perform a cost benefit analysis of the combined wind power prediction/modified unit generation control. The cost benefit analysis would assess the cost benefit analysis could be performed that would assess the cost of the

(a) land for each met tower,

(b) the tower,

(c) the wind speed and direction, pressure, temperature, radar measurements,

(d) communication link,

(e) the computer for calculation of the wind speed prediction for each wind prediction site and the simulation of predicted array power variation,

as a function of the number of met towers measurements or the method used to produce an accurate hour ahead predictor. These costs will be compared with the performance and the savings produced by

(a) increased capacity credit,

(b) reduced production costs,

(c) improved operating reliability,

(d) reduced regulation costs,

(e) improved load following control,

(f)   reduced maintenance costs on conventional units under automatic
      generation control,

(g)   increased unit life,

for different wind conditions. This analysis extends the results of Task 1 on
the error in predicting each wind condition for the trend hour ahead predic-
tors as a function of the number and location of meteorological towers for
each by assessing the costs for providing these predictors at various accuracy
levels as a function of numbers of met towers provided for each. This task
extends the work under task 2 by cumulatively assessing the effectiveness and
cost of both the unit commitment update and generation control possible with
the hour ahead predictors for all wind conditions and met tower number and
location combinations. A cost versus benefit analysis of each predictor that
compares its benefits in increased capacity credits and reduced production,
maintenance and regulation costs against the costs for implementing that
predictor could be made. This analysis would permit decisions on the impor-
tance and priority for investment in the hardware for a specific utility.

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